CANADA

National Energy Board

Reasons for Decision

ENCO Gas, Ltd.

**Grand Valley Gas Company as agent for
The Washington Water Power Company**

Poco Petroleums Ltd.

**San Diego Gas & Electric Company and
Bow Valley Industries Ltd.**

**San Diego Gas & Electric Company and
Canadian Hunter Marketing Ltd.**

**San Diego Gas & Electric Company and
Husky Oil Operations Ltd.**

**San Diego Gas & Electric Company and
Summit Resources Limited**

**Southern California Edison Company and
AEC Oil and Gas Company a division of Alberta Energy
Company Ltd.**

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Imperial Oil Resources Limited**

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GH-6-92

January 1993

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Applications Pursuant to Part VI of the *National Energy Board Act* for Licences to Export Natural Gas

GH-6-92

January 1993

Gas Exports

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder;

AND IN THE MATTER OF applications under Part VI of the *National Energy Board Act* for new licences to export natural gas by:

ENCO Gas, Ltd.; Grand Valley Gas Company as agent for The Washington Water Power Company; Poco Petroleums Ltd.; San Diego Gas & Electric Company and Bow Valley Industries Ltd.; San Diego Gas & Electric Company and Canadian Hunter Marketing Ltd.; San Diego Gas & Electric Company and Husky Oil Operations Ltd.; San Diego Gas & Electric Company and Summit Resources Limited; Southern California Edison Company and AEC Oil and Gas Company a division of Alberta Energy Company Ltd.; Southern California Edison Company and Imperial Oil Resources Limited; Southern California Edison Company and Shell Canada Limited; Southern California Edison Company and Western Gas Marketing Limited; and Summit Resources Limited

AND IN THE MATTER OF Hearing Order GH-6-92, as amended;

HEARD in Calgary, Alberta, on 2nd, 3rd and 4th November 1992.

BEFORE:

K.W. Vollman	Presiding Member
A.B. Gilmour	Member
R. Illing	Member

APPEARANCES:

K. F. Miller	ENCO Gas, Ltd.
K.F. Miller	Grand Valley Gas Company as agent for The Washington Water Power Company
P.J. McIntyre	Poco Petroleums Ltd.
N.M. Gretener	Summit Resources Limited
L.E. Smith J. Walsh	San Diego Gas & Electric Company and Bow Valley Industries; and Canadian Hunter Marketing Ltd.; and Husky Oil Operations Ltd.; and Summit Resources Limited
S. Purcell	Husky Oil Operations Ltd.
L.G. Keough	Southern California Edison Company and AEC Oil and Gas Company a division of Alberta Energy Company Ltd.; and Imperial Oil Resources Limited; and Shell Canada Limited; and Western Gas Marketing Limited
E.S. Decter	Shell Canada Limited
N.D.D. Patterson	Western Gas Marketing Limited
S. Luttyck	Alberta and Southern Gas Co. Ltd.

D.G. Hart, Q.C.	Alberta Natural Gas Company Ltd
S. Trueman R. Fraser	Amoco Canada Petroleum Company Ltd.
F.C. Basham	BP Resources Canada Limited
P.J. McIntyre	Centra Gas Ontario Inc.
G. Walsh D.K. Clark	Czar Resources Ltd.
D.W. Rowbotham	Enserch Development Corporation
B.J. Pierce	Foothills Pipe Lines Ltd.
W. Jackson	Norcen Energy Resources Limited
N. Mills	NOVA Corporation of Alberta
T. Dalgleish L. Clarke	Pacific Gas Transmission Company
D. Dawson G. Giesbrecht	Pan-Alberta Gas Ltd.
K.J. Hadley	PanCanadian Petroleum Limited
R.B. Hillary	Paramount Resources Ltd.
M.A.K. Muir K. MacDonald	ProGas Limited
W.M. Moreland	Alberta Petroleum Marketing Commission
J.A. Snider	Board Counsel

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Abbreviations

$	unless otherwise stated, all funds are in Canadian dollars
Act	*National Energy Board Act*
AEC	AEC Oil and Gas Company a division of Alberta Energy Company Ltd.
AF	Adjustment Factor
Amerada	Amerada Hess Canada Ltd.
ANG	Alberta Natural Gas Company Ltd
APMC	Alberta Petroleum Marketing Commission
AQ	Additional Quantities
Bcf	billion cubic feet
Board	National Energy Board
BQ	Base Quantity
BVI	Bow Valley Industries Ltd.
CHEL	Canadian Hunter Exploration Limited
CHMI	Canadian Hydrocarbons Marketing Inc.
CHML	Canadian Hunter Marketing Ltd.
Court	Federal Court of Appeal
CPUC	California Public Utilities Commission
CWNG	Canadian Western Natural Gas Ltd.
Czar	Czar Resources Ltd.
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EACOG	Southern California Edison Company's weighted average cost of gas

EACOG Multiplier	An annually negotiated factor in some of the gas sales contracts with Southern California Edison Company
EARP Guidelines Order	*Environmental Assessment and Review Process Guidelines Order*
Edison	Southern California Edison Company
EIA	Export Impact Assessment
El Paso	El Paso Natural Gas Company
EMPR	(British Columbia) Ministry of Energy, Mines and Petroleum Resources
ENCO	ENCO Gas, Ltd.
ERCB	(Alberta) Energy Resources Conservation Board
Exclusion List	*List of Automatic Exclusions Pursuant to the EARP Guidelines Order*
Foothills	Foothills Pipe Lines (South B.C.) Ltd.
FS	Firm Service
GHR-1-87	*Review of Natural Gas Surplus Determination Procedures*
GIC	gas inventory charge
GJ	gigajoule(s)
Grand Valley	Grand Valley Gas Company
Husky	Husky Oil Operations Ltd.
Hydro-Québec decision	*Attorney General of Québec* v. *National Energy Board* (1991), 3 F.C. 443
Imperial Oil	Imperial Oil Resources Limited
MAQ	Minimum Annual Quantity
MBP	Market-Based Procedure
MDQ	Maximum Daily Quantity
MMBtu	million British thermal units
MMcf	million cubic feet

MMQ	Minimum Monthly Quantity
MWQ	Minimum Winter Quantity
NEB	National Energy Board
Northwest	Northwest Pipeline Corporation
Northwest Natural	Northwest Natural Gas Company
NOVA	NOVA Corporation of Alberta
PanCanadian	PanCanadian Petroleum Limited
Pan-Alberta	Pan-Alberta Gas Ltd.
Paramount	Paramount Resources Ltd.
PG&E	Pacific Gas & Electric Company
PGT	Pacific Gas Transmission Company
Poco	Poco Petroleums Ltd.
Puget Sound Power	Puget Sound Power & Light Company
QF	qualifying cogeneration facility
RR/P	Remaining Reserves To Production Ratio
SDG&E	San Diego Gas & Electric Company
Shell	Shell Canada Limited
SMDQ	Summer Maximum Daily Quantity
SoCalGas	Southern California Gas Company
Socco	Socco, Inc.
Sumas Cogen	Sumas Cogeneration Company, L.P.
Summit	Summit Resources Limited
tail-end reserves	reserves that will become available following expiry of existing supply contracts
TransCanada	TransCanada PipeLines Limited
Transwestern	Transwestern Pipeline Company

U.S.	United States of America
UEG	Utility Electric Generation
WACOG	Weighted Average Cost Of Gas
WACOG Multiplier	An annually negotiated factor in some of the gas sales contracts with Southern California Edison Company
Westcoast	Westcoast Energy Inc.
Western Gas	Western Gas Marketing Limited
WMDQ	Winter Maximum Daily Quantity
WWP	The Washington Water Power Company

Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-6-92 proceeding, the National Energy Board ("the Board") examined 12 applications for gas export licences. The applications were filed by the following companies:

1. ENCO Gas, Ltd. ("ENCO");
2. Grand Valley Gas Company ("Grand Valley") as agent for The Washington Water Power Company ("WWP");
3. Poco Petroleums Ltd. ("Poco");
4. San Diego Gas & Electric Company ("SDG&E") and Bow Valley Industries Ltd. ("BVI");
5. SDG&E and Canadian Hunter Marketing Ltd. ("CHML");
6. SDG&E and Husky Oil Operations Ltd. ("Husky");
7. SDG&E and Summit Resources Limited ("Summit");
8. Southern California Edison Company ("Edison") and AEC Oil and Gas Company a division of Alberta Energy Company Ltd. ("AEC");
9. Edison and Imperial Oil Resources Limited ("Imperial Oil");
10. Edison and Shell Canada Limited ("Shell");
11. Edison and Western Gas Marketing Limited ("Western Gas"); and
12. Summit;

With the exception of ENCO, all of the applications are for export to California or the Pacific Northwest through the Alberta Natural Gas Company Ltd ("ANG") / Foothills Pipe Lines (South B.C.) Ltd. ("Foothills") / Pacific Gas Transmission Company ("PGT") expansion. In total, the Board examined applications accounting for 9.5 $10^6m^3/d$ (335 MMcfd) of the expansion's design capacity of 25.6 $10^6m^3/d$ (903 MMcfd). These were the first applications to be examined by the Board for licences to export gas on the expansion.

Table 1-1 provides a summary of each export licence application reviewed during the GH-6-92 proceeding.

Table 1-1

Summary of Applied-for Licences

GH-6-92

	Application	Buyer (Type of Market)	Term	Export Point	Maximum Quantities Applied For: Daily 10^3m^3 (MMcf)	Annual 10^6m^3 (Bcf)	Term 10^6m^3 (Bcf)
1.	ENCO	ENCO (cogen. plant)	1 May 1993 or first del. to 31 Oct. 2008	Huntingdon, British Columbia	601.3* (21.2)	219.5* (7.7)	3 258 (115.0)
2.	Grand Valley for WWP	WWP (system supply)	1 Nov. 1993 or first del. for 10 years	Kingsgate, British Columbia	1 563* (55.4)	434* (15.4)	3 357 (119.0)
3.	Poco	Northwest Natural (system supply)	1 Nov. 1993 to 30 Sept. 2003	Kingsgate, British Columbia	445.1 (15.7)	138.8 (4.9)	869.5 (30.7)
4.	Summit	Northwest Natural (system supply)	1 Nov. 1993 to 31 Oct. 2000	Kingsgate, British Columbia	219.2† (7.7)	52.8 (1.9)	300.0 (10.7)
			Sub-total for export to Northwest Natural:		**664.3 (23.4)**	**191.6 (6.8)**	**1 169.5 (41.3)**
5.	SDG&E and BVI	SDG&E (system supply)	11 years following first deliveries	Kingsgate, British Columbia	139.5 (4.9)	50.9 (1.8)	560.0 (19.7)
6.	SDG&E and CHML	SDG&E (system supply)	10 years following first deliveries	Kingsgate, British Columbia	557.6 (19.7)	203.5 (7.2)	2 035.0 (72.0)
7.	SDG&E and Husky	SDG&E (system supply)	10 years following first deliveries	Kingsgate, British Columbia	609.9 (21.7)	222.6 (7.9)	2 226.0 (79.0)
8.	SDG&E and Summit	SDG&E (system supply)	8 years following first deliveries	Kingsgate, British Columbia	195.1 (6.9)	71.2 (2.5)	570.0 (20.0)
			Sub-total for export to SDG&E:		**1 502.1 (52.2)**	**548.2 (19.4)**	**5 391 (190.7)**
9.	Edison and AEC	Edison (power generation)	1 Nov. 1993 to 31 Oct. 2008	Kingsgate, British Columbia	1 445.0 (51.0)	529.0 (18.7)	7 913.0 (279.4)
10.	Edison and Imperial Oil	Edison (power generation)	1 Nov. 1993 to 31 Oct. 2008	Kingsgate, British Columbia	1 445.0 (51.0)	529.0 (18.7)	7 913.0 (279.4)
11.	Edison and Shell	Edison (power generation)	1 Nov. 1993 to 31 Oct. 2008	Kingsgate, British Columbia	1 445.0 (51.0)	529.0 (18.7)	7 913.0 (279.4)
12.	Edison and WGML	Edison (power generation)	1 Nov. 1993 to 31 Oct. 2008	Kingsgate, British Columbia	1 445.0 (51.0)	529.0 (18.7)	7 913.0 (279.4)
			Sub-total for export to Edison:		**5 780.0 (204.0)**	**2 116.0 (74.8)**	**31 652.0 (1 117.6)**
			Total volumes applied for:		10 110.7 (356.25)	3 509.3 (124.06)	44 827.5 (1 583.64)

*. The requested daily and annual volumes vary throughout the licence term. The numbers shown are the maxima requested during the term.

†. The requested daily volume varies between the winter and summer seasons. The number shown is the greater of the two, the winter volume.

1.2 Environmental Screening

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board had complied or would comply with the *Environmental Assessment and Review Process Guidelines Order* ("the EARP Guidelines Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Guidelines Order, the Board would be instituting a screening procedure to examine the potential environmental effects of each export proposal before the Board.

On 9 July 1991, the Federal Court of Appeal ("the Court") issued its decision in the case of *Attorney General of Québec* v. *National Energy Board* (1991), 3 F.C. 443 ("the Hydro-Québec decision"). The Court found that the Board did not have the power to attach conditions relating to electricity production facilities to electricity export licences. In arriving at its decision, the Court considered the definition of "export" under the *National Energy Board Act* ("Act"). The Act provides that "export means, with reference to electricity, to send from Canada by a line of wire or other conductor electricity produced in Canada...". On the basis of that definition, the Court found that "export" does not include production of the commodity to be exported. The Court found that production and exportation are two distinct activities.

In light of this separation of activities, the Court ruled that in considering an electricity export licence application, the only question for the Board to consider "is the environmental consequences of the export, namely the consequences for the environment of (sending) from Canada ...power produced in Canada".[1]

Since the Board's jurisdiction to authorize exports of natural gas is similar to the Board's jurisdiction to authorize exports of electricity, the Board is of the view that the Hydro-Québec decision applies to the regulation of gas exports as well as electricity exports.

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the EARP Guidelines Order. To that end, the Board performed a screening, pursuant to Hearing Order GH-6-92, wherein it considered submissions from each of the applicants.

In response to the Board's information request regarding the EARP Guidelines Order, each applicant filed with the Board information concerning the potential environmental effects and the social effects directly related to those environmental effects that would be caused by the sending or the taking of gas from Canada.

ENCO and WWP submitted that their applications fell under paragraph 12(c) of the EARP Guidelines Order. Specifically, they submitted that the potential environmental effects and the social effects directly related to those environmental effects that would be caused by the applied-for gas export would be insignificant or mitigable with known technology.

The remaining applicants were of the view that their export licence applications should be placed on the Board's *List of Automatic Exclusions Pursuant to the EARP Guidelines Order* ("Exclusion List") as any associated environmental effects had already been adequately addressed in facilities proceedings at the provincial and federal level. These applicants also submitted that a finding

1. Hydro-Québec decision at page 451. On 11 June 1992, the Supreme Court of Canada granted the Grand Council of the Crees (of Québec) leave to appeal the Hydro-Québec decision.

under paragraph 12(c) of the EARP Guidelines Order was an alternative to placing the export licence applications on the Board's Exclusion List pursuant to paragraph 12(a) of the EARP Guidelines Order.

All interested parties were served with copies of the applicants' written submissions. The British Columbia Ministry of Energy, Mines and Petroleum Resources ("EMPR") expressed concern regarding the effects of the Sumas Cogeneration Company, L.P. ("Sumas Cogen") facility on air quality in the lower mainland of British Columbia. ENCO provided additional information that satisfactorily addressed this concern. No other public concerns were identified during the Board's screening of the GH-6-92 gas export applications.

1.2.1 Views of the Board

The Board, by means of a screening pursuant to the EARP Guidelines Order, has completed its environmental screening of the applications considered in this hearing and has concluded that they fall within the ambit of Note 3 of the Board's Exclusion List.[1] The Board is not aware of any public concerns that have not been addressed. Therefore, the applications require no further review.

With respect to the submissions that a finding under paragraph 12(c) of the EARP Guidelines Order was an alternative to a finding under paragraph 12(a) of the EARP Guidelines Order, since the Board is of the view that the applications may be excluded pursuant to paragraph 12(a) of the EARP Guidelines Order, there is no need to consider paragraph 12(c).

1.3 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the Act, which requires that the Board have regard to all considerations that appear to it to be relevant and, in particular, that the Board satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada.

In July 1987, pursuant to a *Review of Natural Gas Surplus Determination Procedures* ("GHR-1-87"), the Board implemented a new procedure, known as the Market-Based Procedure ("MBP"), founded on the premise that the marketplace would generally operate in such a way that Canadian requirements for natural gas would be met at fair market prices.

The MBP provides that the Board will act in two ways to ensure that natural gas to be licensed for export is both surplus to reasonably foreseeable Canadian requirements and in the public interest: it will hold public hearings to consider applications for licences to export natural gas and it will monitor Canadian energy markets on an ongoing basis.

The public hearing portion of the MBP provides that the Board consider:

- complaints, if any, under the Complaints Procedure;

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1. Note 3 provides for the automatic exclusion of "...applications for natural gas exports, imports, exports for subsequent import and imports for subsequent export authorized:

   (ii) by licence where the development of new facilities for production, processing, storage or transmission would not be required."

- an Export Impact Assessment (“EIA”); and
- any other considerations that the Board deems relevant to its determination of the public interest.

The following description of these three components is general in nature and applies to each application heard in GH-6-92.

1.3.1 Complaints Procedure

The basic premise of the Complaints Procedure is that, in a market which is working satisfactorily, Canadian purchasers will be able to obtain domestic natural gas supplies under contract on terms and conditions, including price, similar to those offered to purchasers in the United States of America (“U.S.”). In order to test whether the market is in fact working in this manner, in the GHR-1-87 Decision the Board stated that:

> “The inclusion of a complaints mechanism in the new surplus determination procedures is based on the principle that gas should not be authorized for export if Canadian users have not had an opportunity to buy gas for their needs on terms and conditions similar to those of the proposed export. Applicants for export licences will have to be prepared to address any concerns on this score which may be identified in the complaints procedure…”

The Complaints Procedure seeks to ensure that Canadian gas buyers who have been active in the market have access to gas on terms and conditions no less favourable than export customers. The Complaints Procedure enables these buyers to assess the terms and conditions of the gas sales contracts underlying export licence applications relative to the terms and conditions they are being offered. If the terms and conditions being offered to export customers are more favourable than those available to domestic customers, a Canadian buyer may wish to file a complaint with the Board. The Board would adjudicate each complaint on the basis of an assessment of whether, as a matter of fact, the complainant has or has not been able to obtain additional gas supplies on terms and conditions, including price, similar to those contained in the gas export licence application submitted to the Board.

Domestic gas purchasers who wish to file a complaint must demonstrate that they have attempted to contract for additional gas supplies and that they have not been able to obtain such supplies on terms and conditions similar to those contained in the gas sales contract. At the same time, export licence applicants are expected to respond to concerns expressed by a complainant. If the Board finds that a complaint is valid, it would then have to determine what action needs to be taken to remedy the situation. This could involve a delay in the licence proceeding, a denial of the export licence application or some other action appropriate to the circumstances of the particular application.

1.3.2 Export Impact Assessment

The purpose of the EIA is to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

The Board periodically produces an EIA using several projections of exports. The study, which is prepared in consultation with the natural gas industry and other interested parties, covers

long-term natural gas supply, demand, prices and export levels and endeavours to provide an adequate statement of assumptions and explanation of the analytical technique used.[1]

Applicants and intervenors have the option of using the Board's analysis or of preparing and submitting their own analysis. In the absence of any adjustment-related problems being identified by the Board itself or being raised by interested parties, the Board presumes that the proposed export would not trigger a market-adjustment problem.

1.3.3 The Other Public Interest Considerations

As part of its assessment of the other public interest considerations, the Board normally:

- makes an assessment of the likelihood that licensed volumes will be taken;
- makes an assessment of the durability of gas sales contracts;
- has regard to whether gas sales contracts were negotiated at arm's length;
- verifies that there is producer support for a gas export application;
- verifies that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract; and
- determines the appropriate length of term for an export licence, having regard to:

    (i) evidence on the adequacy of the gas supplies available to the export licence applicant to support the applied-for volumes over the requested licence term;

    (ii) evidence on the necessity of the requested term in light of the terms of the associated gas sales and transportation contracts and the terms of the approvals from other regulatory bodies; and

    (iii) any other evidence which the Board deems to be relevant to the appropriate term of the licence.

The above statement on the other public interest considerations should be interpreted as providing guidance to parties as to which considerations the Board normally has regard to in assessing the merits of gas export licence applications. However, in the context of each specific export licence application, the Board has regard to whatever factors appear to it to be relevant to the Canadian public interest.

In assessing the considerations above, the Board takes into account information regarding gas supply, transportation, markets and sales contracts and the status of regulatory authorizations and contract approvals. This information is provided by the applicant in response to the information filing requirements of the *National Energy Board Part VI Regulations* and during the public hearing process.

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1. By letter dated 3 September 1992, the Board announced that it was undertaking to produce its second EIA. A draft EIA was attached to the letter for comment. A workshop to promote discussion and exchange of information has been arranged for April 1993.

Gas Supply

In its assessment of gas supply, the Board reviews the contractual arrangements pertaining to supply and the adequacy of both reserves and productive capacity.

In making its assessment as to the adequacy of the gas supplies available to the export licence applicant to support the applied-for volumes over the requested licence term, the Board is flexible but normally expects applicants to demonstrate that established reserves are equal to or exceed the applied-for volume and that productive capacity is adequate to meet the proposed annual export volumes over the majority of the applied-for licence term.

Each applicant is required to provide an estimate of established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducts geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's gas reserves.

In its evaluation of gas reserves, the Board makes use of its gas reserves database, which is maintained on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and an assessment of the ownership and contractual status of all pools included in the applications are also done.

The Board uses its estimate of reserves, along with basic deliverability data for each pool for which estimates of reserves were submitted, in preparing its productive capacity projections. These projections are generally adjusted to reflect production at the annual level of requirements. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown in the productive capacity figures are usually based on an annual load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements. If load factors are lower than anticipated, productive capacity would be sustained beyond the time the Board's analysis indicates.

Transportation

Regarding the transportation arrangements underpinning an export project, the Board reviews the status of upstream and downstream transportation arrangements, including all transportation contracts, either in final form or as precedent agreements. The Board also reviews the term and volume of the transportation arrangements.

Markets and Sales Contracts

The applications dealt with in GH-6-92 were for sales to three types of end-use markets: sales for system supply, sales for power generation and sales to cogeneration facilities, which are defined as facilities that produce electricity and thermal energy for use in commercial or industrial operations. The Board's review of these types of markets includes consideration of the following for each market type:

- for exports for system supply and for power generation, consideration of the purchaser's current and projected requirements and supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio; and,

- for exports to a cogeneration facility, consideration of the contractual chain, from the gas contract to the power and thermal sales contracts. The Board also considers the markets for the power and thermal output of the facility and the status of project financing and construction schedules.

For each type of end-use market, the review includes consideration, among other items, of the load factors at which the proposed exports are expected to flow.

The Board's review of the contractual arrangements includes consideration of the contractual obligations between the Canadian sellers and the U.S. buyers, including executed gas sales contracts. The Board's review also includes any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including the filing of these downstream contracts.

Status of Regulatory Authorizations and Contract Approvals

The Board reviews the status of pertinent regulatory authorizations in Canada and the U.S., including provincial removal authorizations, Department of Energy, Office of Fossil Energy ("DOE/FE") import authorization and, for cogeneration facilities, qualifying cogeneration facility ("QF") certification under the U.S. *Public Utility Regulatory Policies Act.*

Regarding contract approvals, the Board's review includes evidence of producer support and the status of any necessary state regulatory commission approvals.

1.4 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial short period of time during which, if the export of gas commences, then the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually starts to flow within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and in each case the applicant indicated that the inclusion of a sunset clause would be acceptable.

As a matter of general policy, and after questioning each applicant, the Board has set the timeframe by which exports must commence at approximately two years from the commencement of the licence term.

1.5 Other Hearing Matters

1.5.1 Exports to California

Czar Resources Ltd. ("Czar") expressed concern about the applications for export to SDG&E and Edison. Specifically, Czar was concerned that the netback prices received under the subject contracts, which are subject to the approval of the California Public Utilities Commission ("CPUC"), would become the yardstick by which the CPUC would measure the acceptability of gas prices for long-term sales to other California utilities. Czar submitted that the Board should withhold approval of the licences until the present discussions between the CPUC and the Governments of Canada, Alberta and British Columbia are concluded and all U.S. regulatory approvals, including the CPUC approval of the subject contracts, are obtained, or, in the

alternative, condition any approval to allow for a review of the eventual effect of those CPUC decisions on the licences.

The applicants supporting the proposed exports to SDG&E and Edison strongly objected to Czar's argument on the grounds that the present discussions with the CPUC regarding exports to northern California are distinct from the subject applications; that the contracts are freely-negotiated, arm's-length transactions; and, that Czar had provided no evidence to support its allegations.

1.5.2 Curtailment of Licences for Reasons of Inadequate Supply

Summit, the applicants supporting the exports to SDG&E and Edison, and Paramount Resources Ltd. ("Paramount") made a number of proposals should the Board determine that the gas supply underpinning an export application is inadequate.

Summit suggested that, rather than reducing the daily volume or reducing the licence term, the Board should reduce the term volume. In the alternative, the Board could provide applicants with an opportunity, through a condition in the licence, to come back and "top up" their gas supply, to the extent necessary, without a further public hearing.

The applicants supporting the export to SDG&E endorsed the recommendations of Summit. SDG&E expanded upon Summit's second proposal by suggesting that the Board could issue a licence subject to the applicant "topping up" its gas supply within a specified time period. If the applicant failed to persuade the Board as to the adequacy of its gas supply during that period, then the licence would reflect a curtailed term.

The applicants supporting the export to Edison endorsed Summit's first proposal, curtailing the term volume only. This option, it was argued, would empower them with the flexibility to continue to operate the contracts. AEC stated that, because the contracts were negotiated on the basis of a number of trade-offs, of which the contract term and term volume were important elements, it would be disappointed if there were any reduction in the term or volume.

Paramount supported SDG&E's expanded proposal but also suggested that communication between the applicant and Board staff be allowed prior to the hearing process. Thus, the applicant would have an opportunity to "top up" its supply prior to the hearing phase should Board staff determine that the supply is deficient. As well, the applicant could remove any reserves additional to those required to support the licence.

The applicants supporting the exports to SDG&E requested that the Board address this matter generally in the Board's decision, in order to provide the industry with a clear identification of the Board's policy.

1.6 Views of the Board

The Board notes that there were no complaints registered with respect to the applications for export licences in the GH-6-92 proceeding.

The 12 applicants examined in these Reasons adopted the Board's most recent EIA, dated 7 September 1989. As neither the Board nor any interested parties identified any adjustment-related problems, the Board concludes that the proposed exports would not trigger a market-adjustment problem.

Since no complaints were registered with respect to the subject applications and the Board has determined that the proposed exports would not trigger a market-adjustment problem, the Board is satisfied that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada.

The remaining chapters of these Reasons review the evidence of each applicant pertaining to the Other Public Interest Considerations. The findings of the Board in respect of these considerations and any other factors the Board has deemed to be relevant are contained in the "Views of the Board" section of each chapter.

Without the support of evidence duly tested through the hearing process, the weight that the Board has given to the Czar argument is not what it would have given to an argument supported by tested evidence. Specifically, Czar did not provide any evidence that the netback prices to other Canadian producers exporting to California utilities would be adversely affected by the netback prices received under the subject contracts. The Board accepts the evidence of the applicants for export to southern California that the commercial transactions were freely negotiated at arm's length. Therefore, the Board is not of the view that it should withhold approval of the subject licences for any reasons cited by Czar.

The Board has not found it necessary to explore the suggestions of applicants relating to methods of remedying supply deficiencies as no curtailments were deemed necessary for the licences sought in this hearing. The Board notes, however, that considerable flexibility exists within the hearing process for applicants to address deficiencies in their supply. Specifically, the Board, through its information requests, may express concerns over the adequacy of an applicant's supply. The applicant then has the opportunity to address these concerns in its response to the Board's information request. The Board has also shown that it is prepared, under the circumstances of a particular application, to use section 21 of the Act to review licence terms in cases where the substance of a licence has not changed and where the applicant is able to bring forward new supply evidence.

Chapter 2

ENCO Gas, Ltd.

2.1 Application Summary

By application dated 6 May 1992, as amended, ENCO sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	commencing on the later of 1 May 1993 or the date of first deliveries and ending on 31 October 2008
Point of Export	-	Huntingdon, British Columbia
Maximum Daily Quantity	-	to 31 Oct. 1993: 155.8 10^3m^3 (5.5 MMcf) 1 Nov. 1993 to 31 Oct. 1994: 429.1 10^3m^3 (15.1 MMcf) after 1 Nov. 1994: 601.3 10^3m^3 (21.2 MMcf)
Maximum Annual Quantity	-	to 31 Oct. 1993: 28.7 10^6m^3 (1.0 Bcf) 1 Nov. 1993 to 31 Oct. 1994: 156.6 10^6m^3 (5.5 Bcf) after 1 Nov. 1994: 219.5 10^6m^3 (7.7 Bcf)
Maximum Term Quantity	-	3 258 10^6m^3 (115 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas to be exported to Sumas Cogen would be produced from gas properties owned or purchased by ENCO within British Columbia and Alberta. The gas would be gathered, processed and transported on the facilities of Westcoast Energy Inc. ("Westcoast") and delivered at Huntingdon, British Columbia. The gas would be shipped from the international border to a cogeneration facility to be constructed near Sumas, Washington on a pipeline owned by Sumas Cogen. Thermal energy and power from the facility would be sold by Sumas Cogen to the steam host, Socco, Inc. ("Socco") and Puget Sound Power & Light Company ("Puget Sound Power") respectively.

2.2 Gas Supply

2.2.1 Supply Contracts

The long-term objective of the gas sales contract is to have ENCO supply the total daily gas requirements of the cogeneration facility from its own reserves. In the near term, due to the unavailability of all necessary Westcoast capacity, and in order to defer production of some of ENCO's reserves, a portion of the cogeneration facility's daily gas requirements will be supplied under third-party contracts with Canadian Hydrocarbons Marketing Inc. ("CHMI"). As exports pursuant to these two contracts would occur under short-term regulatory authorizations, the contracts and supporting reserves are not directly relevant to ENCO's application for an export licence.

Table 2-1

Comparison of Estimates of ENCO's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

ENCO[1]	NEB[2]	Applied-for Volume
3 152 (111.3)	3 084 (108.9)	3 258 (115.0)

1. As of 1 May 1992
2. As of 31 December 1990. The Board's estimate of remaining reserves would be about 116 10^6m^3 (4.1 Bcf) less than shown if further adjusted for production to 1 May 1992.

The reserves submitted by ENCO in support of its export licence application are all owned by ENCO, and thus gas purchase contracts are not necessary.

2.2.2 Reserves

Table 2-1 shows that the Board's estimate of ENCO's reserves is approximately two percent lower than ENCO's estimate and is approximately five percent lower than the applied-for volume. To remedy supply shortages, ENCO may extend its third-party contracts with CHMI. ENCO has also stated that it plans to acquire another 57 10^6m^3 (2 Bcf) to 283 10^6m^3 (10 Bcf) of additional gas reserves.

2.2.3 Productive Capacity

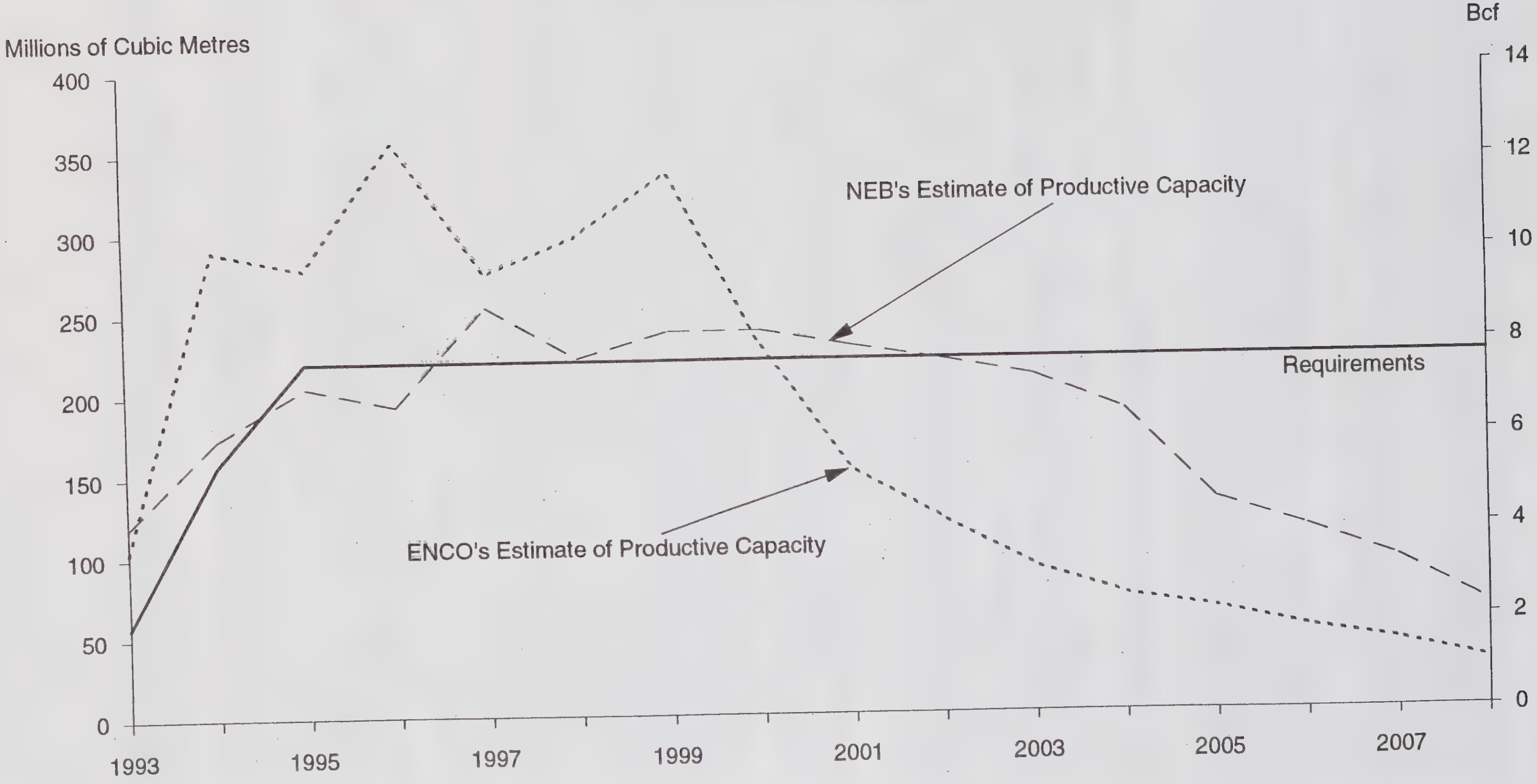
Figure 2-1 compares the Board's and ENCO's projections of productive capacity with the applied-for volumes. ENCO's projection of productive capacity shows that it is capable of meeting its requirements for the first seven years of the fifteen and a half year contract. The Board's projection indicates adequate adjusted productive capacity for the first nine years. ENCO stated it could take care of the potential shortfalls by acquiring additional gas reserves or by extending the third-party contracts with CHMI.

2.3 Transportation

As stated in Section 2.2.1, ENCO expects that it will not have Westcoast gathering, processing and transportation services in place to deliver and sell 23 158 GJ (22,000 MMBtu) for the commencement of first deliveries under the contract. Accordingly, ENCO and Sumas Cogen

Figure 2-1

Comparison of ENCO's and NEB's Estimates of Annual Productive Capacity



have executed a gas management agreement with CHMI pursuant to which CHMI will provide gathering, processing and transportation services on Westcoast to enable ENCO to deliver 12 632 GJ (12,000 MMBtu) at Huntingdon. ENCO and Sumas Cogen have requested additional service from Westcoast for the delivery of 10 526 GJ (10,000 MMBtu) at Huntingdon. Temporary bridging supply will be provided under a third-party contract with CHMI until capacity on Westcoast becomes available.

Westcoast will construct a 300 metre (328 yard) pipeline to connect its pipeline system with the Sumas Cogen pipeline. The Board approved this spur line on 10 September 1992. In the U.S., Sumas Cogen will own and operate a 6.1 kilometre (3.8 mile) pipeline between the border and its facility. Sumas Cogen has obtained all necessary regulatory authorizations for this pipeline and has completed construction and testing.

2.4 Markets and Sales Contracts

The gas proposed for export would be used to fuel a 110 MW cogeneration facility owned by Sumas Cogen. Thermal energy and power from the facility would be sold to the steam host, Socco and Puget Sound Power respectively. The facility's normal daily gas requirement is 23 158 GJ (22,000 MMBtu).

The thermal energy would be sold to Sumas Cogen's affiliate, Socco, which would use the energy in a lumber drying facility to be constructed on the same site as the cogeneration facility. Socco is required to operate the kiln facility so as to maintain the cogeneration facility's QF status.

Power from the plant would be sold to Puget Sound Power as baseload. Puget Sound Power generates, purchases, transmits, distributes and sells electric power in western and central Washington state. The utility serves a population exceeding 1.6 million people.

Financial closing for the project, including funds for the purchase of property and construction of the cogeneration and kiln facilities, occurred in the winter of 1992. Construction of the cogeneration facility began in March 1992 and the facility is expected to commence commercial operations in May 1993. The cogeneration facility is expected to nominate gas at a 92.5 percent load factor.

ENCO and Sumas Cogen have executed a gas sales contract dated 23 December 1991. The term of this contract is for 20 years following commencement of commercial operations of the cogeneration facility. The contract is subject to receipt of Canadian and U.S. regulatory authorizations and execution of transportation arrangements upstream of Huntingdon, British Columbia by 15 October 1993.

ENCO is a wholly-owned subsidiary of Sumas Cogen. Thus, when preparing the contract, ENCO and Sumas Cogen took into account that negotiations were not at arm's length. Specifically, consideration was given to ensuring that the pricing structure contained in the contract met the standard set by Revenue Canada for "arm's length".

The initial daily contract quantity ("DCQ") is 12 632 GJ (12,000 MMBtu). The DCQ will increase as ENCO obtains additional capacity on Westcoast.

The price is contractually set at $U.S. 1.818/GJ ($U.S. 1.954/MMBtu) in the first contract year. This initial price escalates after the first year by an annual rate of 7.5 percent until 31 October 2000. For the remainder of the contract term, the price escalates at four percent per annum.

Should Sumas Cogen not nominate the DCQ, then it is obligated to compensate ENCO for all expenses incurred by ENCO, including transportation and processing charges for the gas not purchased.

ENCO estimated that the price that would have occurred under the terms of this contract at the British Columbia border as of 1 January 1992 was equal to $2.308/GJ ($2.19/MMBtu).

Sales of electricity to Puget Sound Power from the cogeneration facility would occur pursuant to an executed agreement for firm power purchase. The term of the agreement is for 20 years following the date of commercial operation. The price is the sum of a fixed energy payment, as set out in a schedule to the agreement, and a variable energy payment escalated by the rate of inflation.

The sale of thermal energy to Socco would occur pursuant to a 20-year thermal energy and kiln lease agreement.

2.5 Status of Regulatory Authorizations and Contract Approvals

On 15 May 1992, ENCO filed an application for a British Columbia energy removal certificate for a term and volume commensurate with the subject licence application. An application will be filed with the Energy Resources Conservation Board ("ERCB") for a removal permit when reserves from Alberta are required for the export.

ENCO expected a DOE/FE decision soon on its 24 February 1991 application for import authorization. As well, an application was filed 13 August 1992 with the Federal Energy Regulatory Commission for recertification of the cogeneration facility as a QF.

The Washington Utilities and Transportation Commission has approved the power purchase agreement.

2.6 Views of the Board

The Board notes that Sumas Cogen is obligated to reimburse ENCO for all expenses incurred by ENCO, including transportation and processing charges for the gas not purchased. The Board is also cognizant that the markets for the electricity and thermal energy are likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board is of the view that the price under the gas sales contract will likely escalate at a rate generally comparable to that under the power purchase contract. As well, the Board takes comfort in ENCO's evidence that there are no foreseeable circumstances that would cause ENCO and Sumas Cogen to terminate the gas sales contract. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The gas sales contract was not negotiated at arm's length. However, the Board is satisfied that the terms and conditions of the contract, including the netback price, are comparable to those contained in other gas export contracts that have been negotiated at arm's length.

As ENCO is relying on its own gas supply for the proposed export, a finding of producer support is not necessary. CHMI will be providing temporary bridging supply to ENCO but this gas will

be exported under short-term removal and export authorizations and hence does not form part of ENCO's gas supply supporting the subject application.

The Board notes that the contract price escalates at a rate greater than the rate by which Canadian demand charges are expected to escalate during the term of the contract. The Board also recognizes that Sumas Cogen is obligated to compensate ENCO for all expenses incurred by ENCO, including transportation and processing charges, for contractual volumes not nominated by Sumas Cogen. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

Regarding the adequacy of supply, the Board's estimate of reserves is approximately five percent lower than the applied-for volume. The Board's estimate of productive capacity shows that ENCO can meet its requirements from existing supply for the first nine years of the proposed licence term. Backstopping from CHMI and purchases of additional gas would likely allow ENCO to meet its requirements for the remainder of the licence term. As well, the Board observes that the terms of the gas sales, power purchase and thermal energy contracts and of the DOE/FE import authorization are for 20 years. Transportation service has been arranged and an energy removal certificate application has been submitted for a term and volume commensurate with that requested hereunder. The Board is therefore satisfied that the requested licence term is appropriate.

2.7 Decision

The Board has decided to issue a gas export licence to ENCO, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Chapter 3

Grand Valley Gas Company as agent for The Washington Water Power Company

3.1 Application Summary

By application dated 30 November 1990, as amended, WWP, by its agent Grand Valley, sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	ten years from the date of first deliveries
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	See Table 3-1
Maximum Annual Quantity	-	See Table 3-1
Maximum Term Quantity	-	3 357 10^6m^3 (119.0 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas proposed for export would be produced from pools in Alberta owned by three producers: AEC, Amerada Hess Canada Ltd. ("Amerada") and PanCanadian Petroleum Limited ("PanCanadian"). The gas would be transported on the NOVA Corporation of Alberta ("NOVA") system for delivery to WWP near Coleman, Alberta. WWP would ship the gas through the ANG/Foothills system in Canada for export near Kingsgate, British Columbia. The gas would then flow on PGT for delivery into the WWP system at various points in Washington and Idaho. WWP is an electric and gas utility serving the Pacific Northwest.

3.2 Gas Supply

3.2.1 Reserves

Contractually, AEC, Amerada and PanCanadian may supply the proposed export from their corporate reserves. Accordingly, no specific pools have been dedicated to the sale. Estimates of the AEC, Amerada and PanCanadian reserves submitted in support of this application are shown in Table 3-2. The producers' estimates of these reserves total 31 271 10^6m^3 (1,103.9 Bcf), approximately nine times greater than the applied-for export volume of 3 357 10^6m^3 (119 Bcf). The Board's estimate of reserves is six percent lower than the estimate submitted by WWP, but is nearly double the three producers' expected requirements of 15 553 10^6m^3 (549 Bcf).

The Board's estimate of AEC's reserves is approximately nine percent less than AEC's estimate and is 68 percent greater than AEC's total requirements. AEC's total requirements include,

Table 3-1

WWP's Maximum Applied-for Daily and Annual Quantities

Contract Year Commencing	Daily Quantity 10^3m^3	MMcf	Annual Quantity 10^6m^3	Bcf
1 November 1993	1 013	35.9	277	9.8
1 November 1994	1 100	39.0	302	10.7
1 November 1995	1 190	42.2	328	11.6
1 November 1996	1 285	45.6	356	12.6
1 November 1997	1 380	48.9	382	13.5
1 November 1998	1 471	52.2	408	14.5
1 November 1999	1 563	55.4	434	15.4
1 November 2000	1 145	40.6	275	9.8
1 November 2001	1 201	42.6	290	10.3
1 November 2002	1 258	44.6	305	10.8

Table 3-2

Comparison of Estimates of Producers' Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

	Supplier's[1] Estimate	NEB[1]	Applied-for[2] Volume
AEC	14 755 (520.9)	13 387 (472.6)	N/A
Amerada	4 766 (168.2)	4 724 (166.8)	N/A
PanCanadian	11 750 (414.8)	11 255 (397.3)	N/A
Total WWP	31 271 (1,103.9)	29 366 (1,036.7)	3 357 (118.5)

1. As of 31 December 1991.
2. Total requirements are 7 950 10^6m^3 (280.6 Bcf) for AEC, 1 017 10^6m^3 (35.9 Bcf) for Amerada and 6 586.4 10^6m^3 (232.5 Bcf) for PanCanadian.

among other requirements, volumes for both the WWP and joint Edison/AEC export applications examined in these Reasons.

AEC's estimate of reserves includes a corporate reserve pool of undedicated reserves, reserves that will become available following expiry of existing supply contracts ("tail-end reserves") and stored gas. AEC provided ERCB estimates of its corporate reserve pool, which represent approximately 34 percent of AEC's submitted reserves. Tail-end reserves, located in the shallow gas formations of the Suffield field, comprise approximately 64 percent of AEC's submitted reserves. These reserves are currently under contract but will become available to AEC when the contracts expire. One contract, with Canadian Western Natural Gas Ltd. ("CWNG"), expires on 31 October 1996 and the other contract, with TransCanada PipeLines Limited ("TransCanada"), expires on 31 October 2001. AEC used ERCB initial reserves estimates and its own production forecasts to determine the estimate of tail-end reserves. Less than two percent of AEC's reserves estimate is attributed to stored gas. AEC owns and operates an underground gas storage facilities in the Upper Mannville I pool in Suffield. The storage facility contained 270.6 10^6m^3 (9.5 Bcf) of undedicated gas reserves as of 31 January 1992.

Amerada provided ERCB estimates of reserves for all its submitted pools, except the Cranberry Slave Point A, Ricinus Cardium R, Viking A and Viking J pools. Amerada submitted its own reserves estimates for these pools. Table 3-2 shows that the Board's estimate of Amerada's reserves is approximately equal to Amerada's estimate and that both estimates are more than 4.5 times greater than the expected requirements.

PanCanadian provided ERCB estimates of its submitted reserves. The Board's estimate of PanCanadian's reserves is approximately four percent lower than that submitted by PanCanadian and 42 percent more than PanCanadian's total requirements.

Overall, the Board's estimate of reserves for the three producers is double their total requirements and about eight times WWP's proposed export.

3.2.2 Productive Capacity

The contracts between WWP and AEC, Amerada and PanCanadian require each producer to meet a specified daily rate, which total to the applied-for daily rate. There are no contractual provisions for one producer to make up the deliverability shortfalls of another producer. Therefore, the Board analysed productive capacity for each producer separately.

Figure 3-1 compares the Board's and AEC's projections of productive capacity, exclusive of stored gas, with AEC's total requirements. AEC's total requirements include previously approved export volumes and the WWP and Edison volumes examined in these Reasons. Both projections indicate minor shortfalls in productive capacity during some years between 1994 and 2001. AEC intends to remedy these shortfalls by making net withdrawals from its storage facility during those years. The Board, using its own projections of productive capacity, has determined that all yearly inventory, injection and withdrawal rates for the storage facility meet the design parameters described by AEC. This should allow AEC to meet all its requirements throughout the applied-for term.

The projections of AEC's productive capacity increase substantially during the years 1997 and 2002. These increases coincide with the expiration of the CWNG and TransCanada contracts respectively.

Figure 3-1
Comparison of AEC's and NEB's Estimates of Annual Productive Capacity

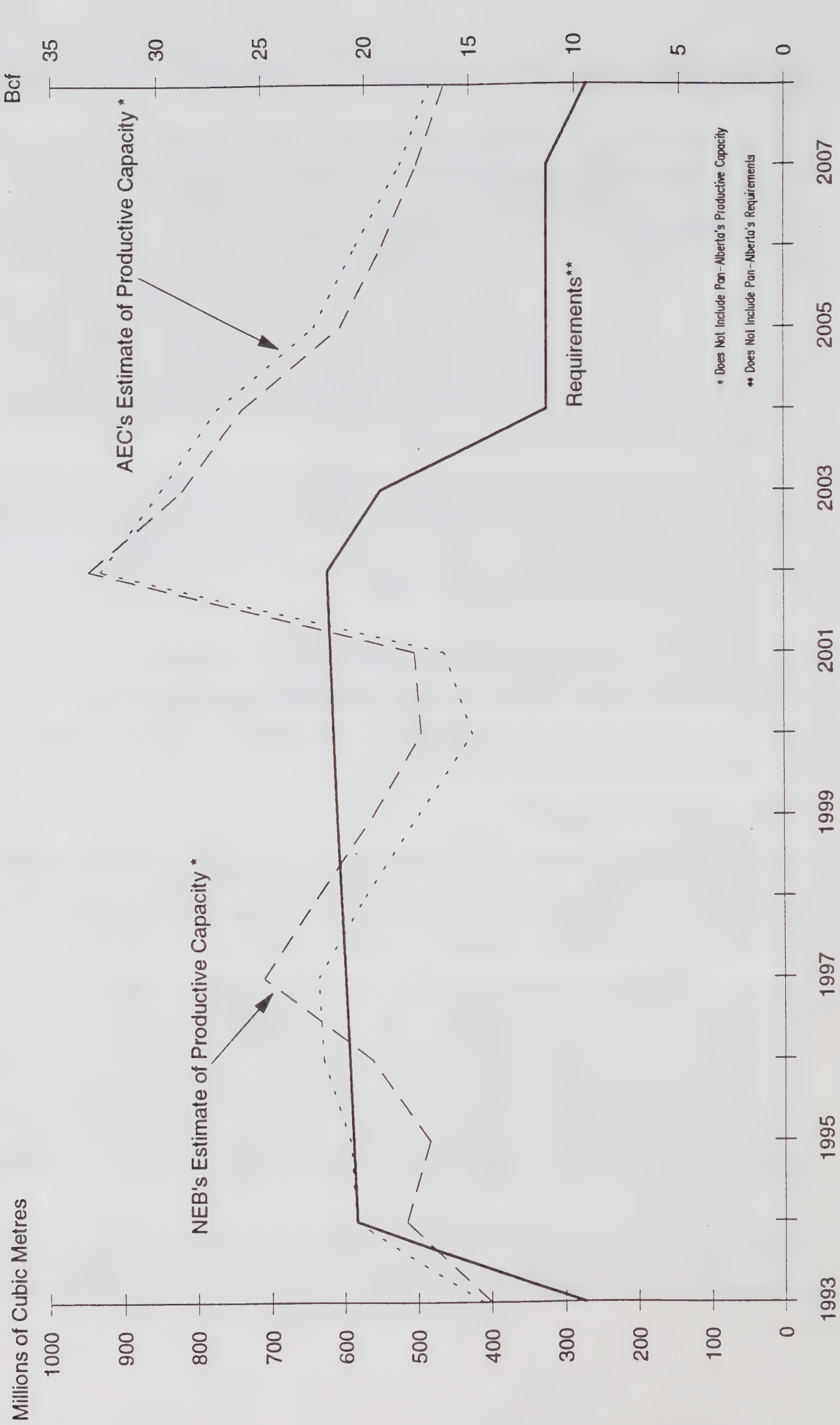


Figure 3-2 compares the Board's and Amerada's projections of productive capacity with Amerada's requirements. Both projections indicate more than adequate gas supply to meet the requirements throughout the proposed export term.

Figure 3-3 compares the Board's and PanCanadian's projections of adjusted productive capacity with PanCanadian's requirements. Both projections indicate adequate productive capacity.

3.3 Transportation

AEC, PanCanadian and WWP originally obtained firm service ("FS") transportation on NOVA under contracts dated 1 September 1991. Amerada did not contract for service on NOVA at that time. To facilitate the security arrangements required by NOVA for its expansion facilities, PGT accepted assignment of these contracts. The contracts will be re-assigned to the three producers, with the WWP/NOVA contract being assigned to Amerada, once the security and financial agreements are signed between the producers and NOVA. All transportation arrangements are for a term and volume not less than that applied-for.

WWP executed a 30-year FS transportation contract with ANG dated 12 June 1991 for a daily quantity of 565 10^3m^3 (20,000 MMBtu). WWP also holds 30-year FS transportation contracts on ANG/Foothills and PGT, which it acquired from CP National Corporation. As well, WWP signed a 30-year FS transportation contract with PGT dated 25 April 1991.

The contracted capacity on ANG/Foothills and PGT is sufficient for the applied-for volumes for the November to March period. WWP holds more capacity on ANG/Foothills and PGT from November to March than it does from April to October in order to accommodate the AEC contract, which only operates during the former period.

The required expansion facilities in the U.S. are currently under construction and are expected to be in service by 1 November 1993.

3.4 Markets and Sales Contracts

WWP is an investor-owned electric and natural gas utility operating in parts of Washington, Idaho, Oregon and northeast California. It serves 25 counties with Spokane County, Washington being the largest. Sales between October and March represent approximately 65 percent of WWP's annual sales. WWP's total 1991 gas sales were 572 10^6m^3 (20.2 Bcf).

WWP's current supply portfolio includes firm and spot gas purchases delivered through Northwest Pipeline Corporation ("Northwest"). WWP purchased approximately 38 percent of its 1991 supplies under short-term arrangements from Alberta delivered through the PGT system. WWP anticipates that the proposed export volumes will significantly reduce its present short-term gas purchases from Canada.

WWP anticipates that the export volumes will represent 40 percent of its average total daily purchases in 1993 and 50 percent in 2003. WWP projected that its firm system sales will grow at an annual average of between 2.1 percent under its low growth scenario and 3.9 percent under its high growth scenario over the 1992-2003 period. WWP attributes the continued core market growth to a number of factors including the following:

- increased employment opportunities in Spokane County;

Figure 3-2

Comparison of Amerada's and NEB's Estimates of Annual Productive Capacity

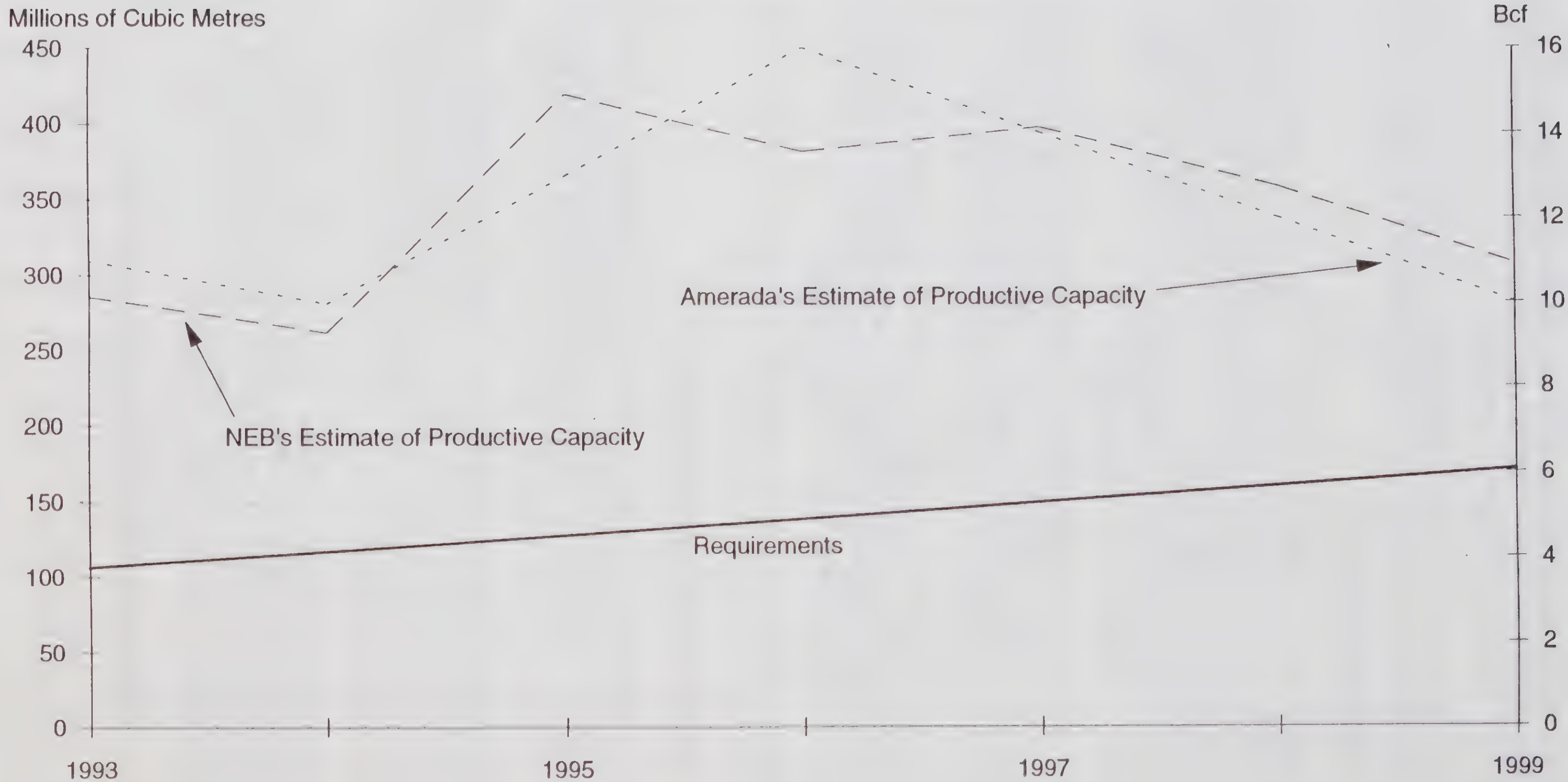


Figure 3-3

Comparison of PanCanadian's and NEB's Estimates of Annual Productive Capacity

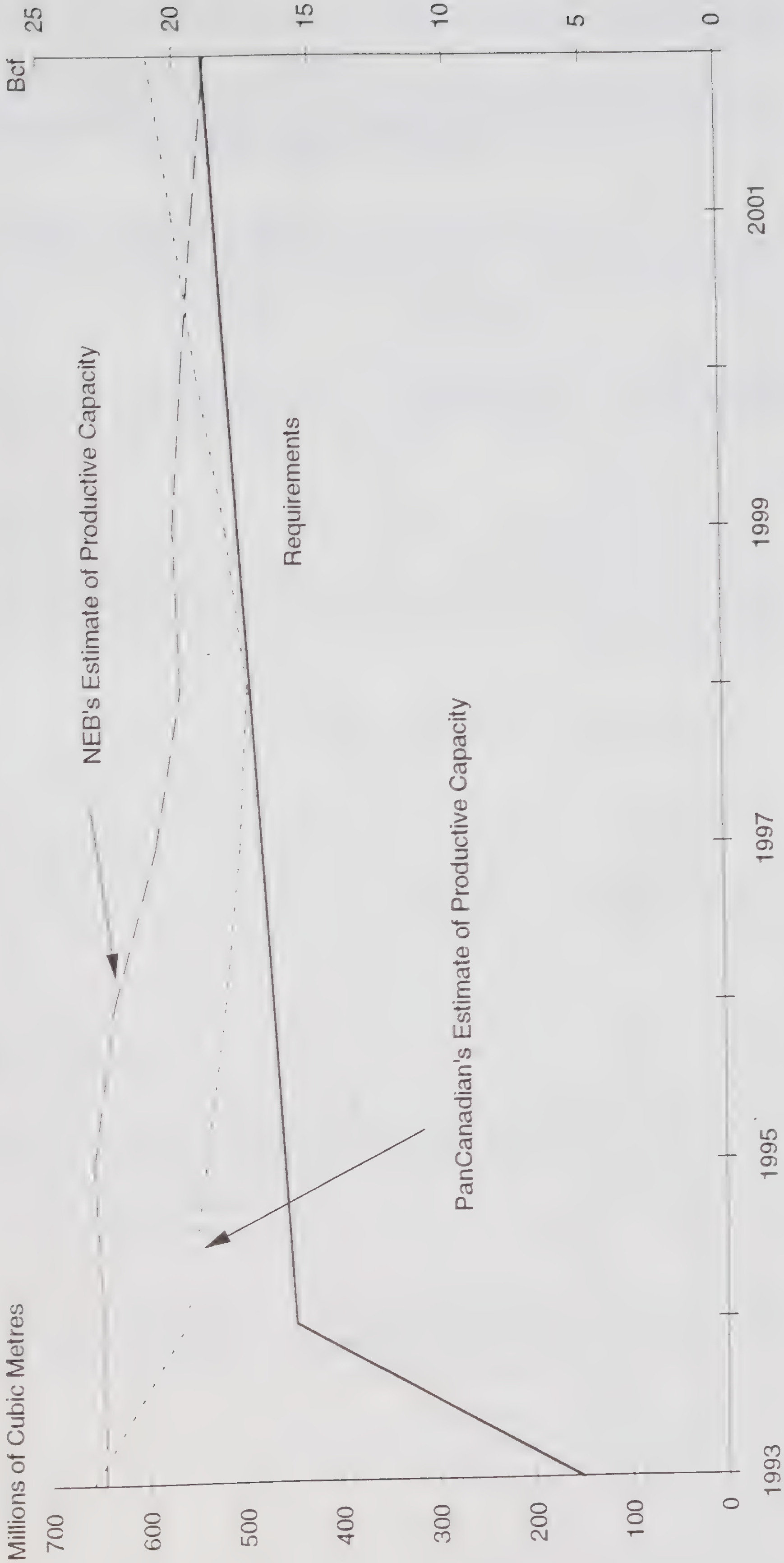


Table 3-3

Maximum Daily Quantities and Minimum Take Quantities under the Contracts with WWP

	AEC Contract[1]	PanCanadian Contract[2]	Amerada Contract[2]
Maximum Daily Quantity	435.7 10^3m^3 (15.5 MMcf)	282 10^3m^3 (10 MMcf)	304.6 10^3m^3 (10.8 MMcf)
Minimum Take Quantity	211.2 10^3m^3 (7.5 MMcf)	70 percent of MDQ	50 percent of MDQ

1. The AEC contract provides for nominations between November and March only.
2. The MDQ increases by a preset amount in each succeeding contract year.

- forecasted increase in population; and
- increased conversions of space heating and water heating to gas from electricity.

WWP anticipates that the export volumes will help diversify its existing supply portfolio and will safeguard against supply interruptions to its core market. WWP stated that the load factor over the contract term in the winter and summer seasons would average 90 percent and 75 percent respectively.

WWP executed gas sales contracts, as amended, with AEC, Amerada and PanCanadian in October and December, 1991. The AEC contract begins on the earlier of the day that firm deliveries commence or firm service is available on NOVA, ANG/Foothills and PGT, and ends ten years later. The PanCanadian contract begins on the later of 1 November 1993 or the date when all conditions precedent have been satisfied, and also ends ten years later. The Amerada contract begins on the same date as the PanCanadian contract but ends after seven years. For the Amerada and PanCanadian contracts, the commencement of firm deliveries is expected to occur by 1 November 1994. For the AEC contract, the commencement of firm deliveries can be deferred to 1 November 1995. The AEC contract provides for deliveries between November and March. Volumes not nominated during this period may be delivered between April and October.

All three contracts may be extended annually, subject to mutual agreement of the parties. The contracts provide for the maximum daily quantities ("MDQs") and minimum takes shown in Table 3-3. The Amerada and PanCanadian contracts are subject to the receipt of all regulatory

approvals by 1 December 1992.[1] The AEC contract is subject to the receipt of all regulatory approvals by 1 November 1993. WWP stated that the contracts were negotiated at arm's length.

AEC may reduce the MDQ proportionally if WWP nominates less than the Minimum Winter Quantity ("MWQ") more than three times in five or fewer successive winters. The MWQ is defined as preset percentages of the MDQ in the AEC contract. Either party may terminate the contract if the MDQ falls below 142 10^3m^3 (5 MMcf).

Amerada and PanCanadian may reduce the Minimum Annual Quantity ("MAQ") proportionally if WWP nominates less than the respective minimum annual takes. Amerada and PanCanadian may terminate their contracts if WWP's takes are less than 30 percent and 40 percent respectively of the MAQ.

WWP must pay a deficiency charge for volumes not nominated. The deficiency charge equals 20 percent of the commodity rate under the Amerada and AEC contracts and 25 percent under the PanCanadian contract. WWP may recover the deficient volumes after taking the MAQ and MWQ in the next contract year under the respective contracts.

The price under each contract equals the NOVA demand charge and the commodity charge. The contracts stipulate that the parties are to share any costs attributable to demand charges for unutilized NOVA capacity. The commodity charge is negotiated annually and is based on the prices of WWP's gas purchases and the producers' sales to other markets. The commodity charge cannot exceed WWP's weighted average cost of gas ("WACOG"). If price negotiation is unsuccessful, then either party may initiate arbitration before 1 November of the contract year.

WWP estimated that the netback prices that would have been in effect under the terms of these contracts at Coleman, Alberta as of January 1992 would have been in the range of \$1.50/GJ (\$1.58/MMBtu) to \$2.10/GJ (\$2.21/MMBtu).

3.5 Status of Regulatory Authorizations and Contract Approvals

AEC, Amerada and PanCanadian applied to the ERCB in September and October 1992 for removal permits for terms and volumes commensurate with the respective contracts. WWP expected to apply to the DOE/FE for import authorization by 1 December 1992. Decisions on the applications are pending. All transportation expansion facilities received regulatory authorizations.

3.6 Views of the Board

The Board notes that WWP must pay a deficiency charge for volumes not nominated. WWP is also obligated to make minimum gas nominations or risk curtailed volumes or termination of the sales contracts. The Board also recognizes that the growing WWP market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board observes that the contract price is market sensitive since it is negotiated annually based on market prices and may be arbitrated if necessary. As well, the Board takes comfort in WWP's evidence that it is unlikely that any circumstances would occur that would cause either

1. By letter dated 28 January 1993, WWP advised the Board that the date for the satisfaction of conditions precedent contained in the Amerada and PanCanadian contracts had been extended to 1 December 1993.

party to terminate the gas sales contract. The Board is thus satisfied that the sales contracts will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contracts and notes that they have been negotiated at arm's length.

As AEC, Amerada and PanCanadian are each relying on their own gas supply for the proposed export, a finding of producer support is not necessary.

The Board notes that WWP is directly responsible for all transportation charges on ANG/Foothills and is contractually obligated to compensate the producers for the NOVA demand charges associated with nominated volumes. The contracts also stipulate that the parties are to share any costs attributable to demand charges for unutilized NOVA capacity. The Board is therefore satisfied that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

Regarding the adequacy of supply, the Board's estimate of total reserves for the three suppliers is nine times larger than the applied-for volume and is nearly twice the total expected requirements for the three suppliers over the applied-for term. The Board's projection of AEC's productive capacity shows some minor shortfalls in the early part of the applied-for term. However, the Board is satisfied AEC can meet its requirements by drawing on undedicated gas from its storage facility. The Board's estimates of Amerada's and PanCanadian's productive capacity show adequate supply throughout the proposed term. The Board also observes that the terms and volumes of the gas sales contracts are commensurate with the applied-for licence. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume commensurate with the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

3.7 Decision

The Board has decided to issue a gas export licence to WWP, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Chapter 4

Poco Petroleums Ltd.

4.1 Application Summary

By application dated 14 November 1991, Poco applied for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 November 1993 or the date when all Conditions Precedent in the gas purchase contract between Northwest Natural Gas Company ("Northwest Natural") and Poco have been satisfied, and continuing until 30 September 2003.
Point of Export	-	Kingsgate, British Columbia
Maximum Daily Quantity	-	445.1 10^3m^3 (15.7 MMcf)
Maximum Annual Quantity	-	138.8 10^6m^3 (4.9 Bcf)
Maximum Term Quantity	-	869.5 10^6m^3 (30.7 Bcf)
Tolerances	-	ten percent per day and two percent per year.

The gas proposed for export would be produced from reserves owned or controlled by Poco in Alberta. The gas would be transported in Canada on NOVA and ANG/Foothills to the international border near Kingsgate, British Columbia. In the U.S., PGT and Northwest would ship the gas to Northwest Natural, an LDC serving markets in the states of Washington and Oregon.

4.2 Gas Supply

4.2.1 Reserves

Poco will provide the gas for the proposed export from its export reserve pool. Therefore, no specific pools have been contractually dedicated to the proposed export. Poco stated that its inventory of reserves available for export consists of 8 017 10^6m^3 (283.1 Bcf) of established reserves plus 3 500 10^6m^3 (123.6 Bcf) of undiscovered potential. This export reserve pool will be used to provide 5 811 10^6m^3 (205.3 Bcf) of gas: the remaining requirements of the GL-117, GL-118, GL-173 and GL-174 licences and the subject volumes at expected rates of take.

Table 4-1 shows that the Board's estimate of Poco's established gas reserves is seven percent lower than Poco's, and that both estimates are approximately eight times larger than the applied-for volume. The Board's estimate of Poco's established reserves is 28 percent larger than Poco's total expected requirements. The Board's estimate of Poco's undiscovered potential is similar to Poco's. Poco's undiscovered potential is not discussed further in these Reasons as the productive capacity from the established reserves is adequate to meet the requirements of the applied-for licence.

Table 4-1

Comparison of Estimates of Poco's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Poco	NEB	Applied-for Volume
8 017[1] (283.1)	7 436[1] (262.6)	870[2] (30.7)

1. as of 31 December 1991.
2. This represents only a portion of Poco's total commitments that must be supplied from these reserves. Poco's total commitments, including the new volumes for Northwest Natural, are 5 811 10^6m^3 (205.1 Bcf) at expected rates of take.

4.2.2 Productive Capacity

The Board's and Poco's estimates of productive capacity for established reserves are compared to Poco's average annual requirements in Figure 4-1. The Board's estimate of adjusted productive capacity is lower than Poco's but indicates that there would be sufficient supply available to meet average annual requirements for the majority of the term. The minor shortfall in 1998 could be adequately met by developing some of Poco's potential reserves.

Poco also submitted a projection of its total corporate supply/demand balance to the year 2004. That projection indicated that Poco has sufficient corporate supply available to meet all its current corporate sales commitments.

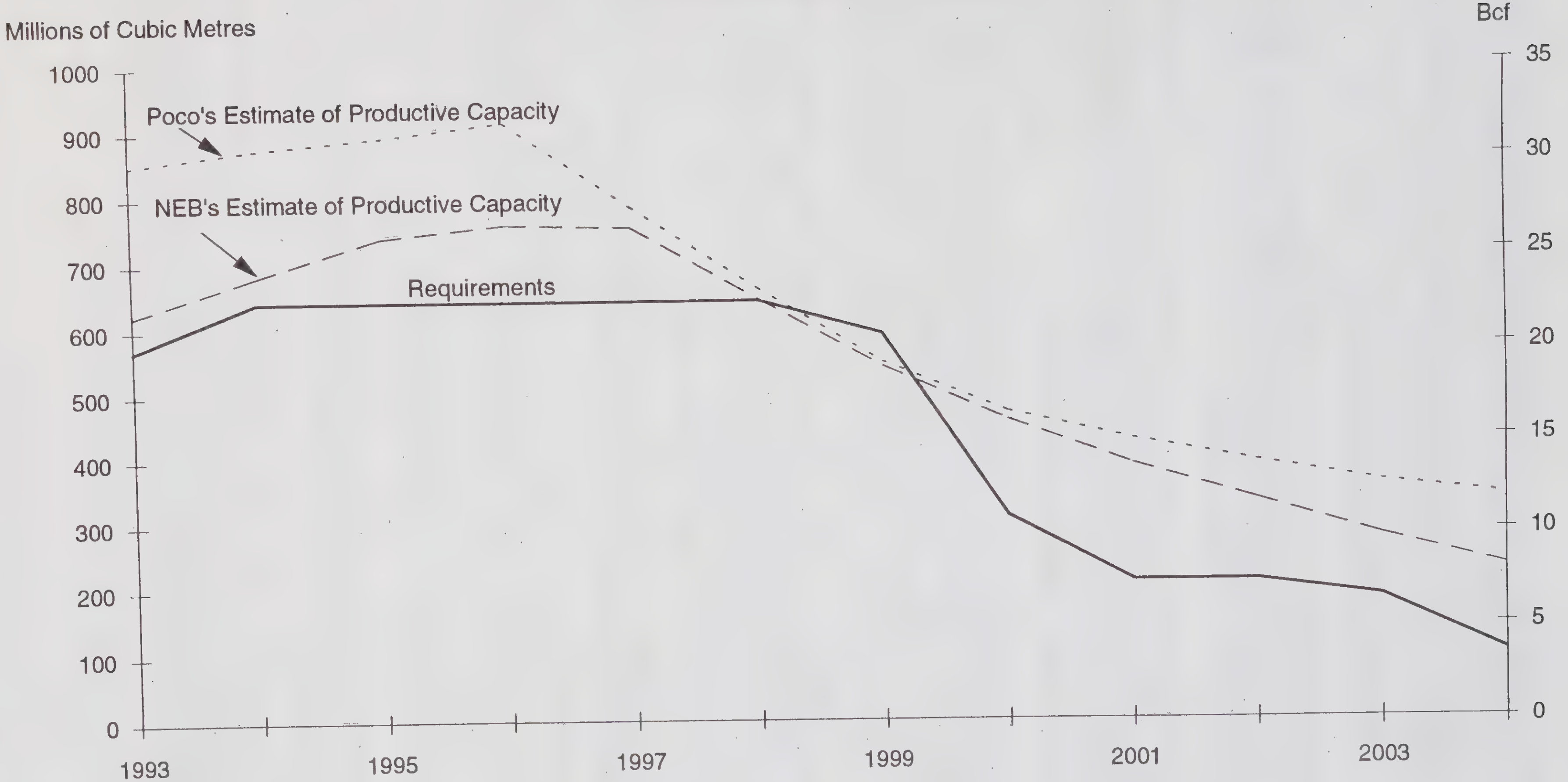
4.3 Transportation

Poco executed an FS contract, dated 1 September 1991, with NOVA to deliver the proposed export volumes from receipt points in Alberta to the British Columbia border at Coleman. Northwest Natural concluded an agreement with ANG, dated 12 June 1991, to transport the gas on ANG/Foothills' system to the international boundary near Kingsgate, British Columbia. Northwest Natural will temporarily assign a portion of its ANG/Foothills capacity to Poco for a term and volume consistent with the gas sales contract.

In the U.S., Northwest Natural executed an FS transportation contract with PGT, dated 25 April 1991, under which the export quantities would be delivered to a point of interconnection with the

Figure 4-1

Comparison of Poco's and NEB's Estimates of Annual Productive Capacity



facilities of Northwest. In turn, under an arrangement with Northwest dated 29 June 1990, Northwest Natural acquired FS transportation of the gas to its citygate.

All transportation agreements are for terms and volumes commensurate with the subject application.

4.4 Markets and Sales Contracts

The gas will be sold to Northwest Natural, an LDC serving more than 320,000 residential, commercial, industrial, cogeneration and electric generation customers in Oregon and Washington. The company provides both sales and transportation service and, in total, delivers more than 2 830 10^6m^3 (100 Bcf) annually.

Growth in the number of customers and in total deliveries averaged 3.7 percent and 5.2 percent per year respectively between 1985 and 1990. Northwest Natural forecasts that sales will increase by two percent per year during this decade. This forecast is based on the current low per capita use of natural gas in its service territory and on the competitive price of natural gas compared to other fuels, such as oil and electricity.

Northwest Natural opened its distribution system to transportation service in 1988, paralleling the deregulation of the interstate pipeline system. During the period 1987 to 1989, transportation volumes increased from five percent to 55 percent of annual deliveries, with a corresponding decrease in sales volumes, largely in the industrial sector. Thus, Northwest Natural now forecasts that all incremental industrial loads will be served by transportation volumes. The expected growth in sales will, therefore, come predominantly from the residential and commercial sectors.

Northwest Natural currently purchases about two-thirds of its gas requirements from Canada. The company owns or contracts for storage capacity at five different facilities. Northwest Natural relies on this capacity to meet more than one-half of its peak day firm load and about 20 percent of its annual requirements. On a peak day, the applied-for volumes would represent about seven percent of Northwest Natural's total supply portfolio.

Poco expected that exports would occur at summer and winter load factors of 50 and 70 percent respectively, for an annual average of approximately 60 percent.

Northwest Natural and Poco executed a gas sales contract on 1 June 1991, with an initial term extending to 30 September 2003. The contract continues from year to year thereafter until cancelled by either party on six month's written notice. The contract provides for a winter MDQ ("WMDQ") and a summer MDQ ("SMDQ") of 445.1 10^3m^3 (15.7 MMcf) and 315.5 10^3m^3 (11.1 MMcf) respectively. The contract is subject to the receipt of regulatory authorizations by 1 November 1994. Poco stated that the contract was negotiated at arm's length.

Northwest Natural must purchase at least 50 percent of the WMDQ and SMDQ. If it does not, Northwest Natural will pay a fee of 20 percent of the applicable commodity charge on the deficient quantity.

The contract includes a two-part pricing structure, consisting of a demand charge and a commodity price, at the point of delivery. The contractual point of delivery is the interconnection of the NOVA and ANG/Foothills systems. The parties, however, amended the contract on 13 October 1992 to provide an option to Poco to change the point of delivery to Kingsgate.

The demand charge component will be a monthly amount equal to Poco's demand charge obligations to transport the export volumes to the delivery point. The commodity component will consist of a summer season price and a winter season price, which will be determined annually based on market conditions. The parties expect to meet on 1 September 1993 to negotiate mutually acceptable commodity prices for the first contract year. In arriving at the commodity prices, the price of other gas sold under similar terms and conditions in the Pacific Northwest from U.S., British Columbia and Alberta sources will be considered.

The contract provides for binding arbitration in the event that Poco and Northwest Natural are unable to agree on winter and summer season commodity prices. Arbitration would consider such factors as the opportunities available to Poco to sell gas to others, to Northwest Natural to purchase gas from others, and the price of other gas sold under similar service and conditions in the same or similar markets.

Poco submitted that, on 1 January 1992, the Alberta border price that would have been in effect under the terms of this contract would have been $1.79/GJ ($1.88/MMBtu).

4.5 Status of Regulatory Authorizations and Contract Approvals

On 21 October 1992, Poco applied to the ERCB for a removal permit. Poco anticipated a decision in late 1992 or early 1993. As well, Northwest Natural has applied to the DOE/FE for import authorization. A decision is expected early in 1993.

4.6 Views of the Board

The Board notes that Northwest Natural must nominate at least 50 percent of the WMDQ and SMDQ if it is to avoid payment of a deficiency charge. The Board also recognizes that the market for the gas is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board has noted the market-oriented approach, including binding arbitration, used to determine the commodity prices on an annual basis. As well, the Board takes comfort in Poco's evidence that it is unlikely that any circumstances would occur that would cause Poco and Northwest Natural to terminate the gas sales contract. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned or controlled by Poco, a finding of producer support is not necessary.

The Board notes that the contract price contains a demand charge component equal to Poco's demand charge obligations to transport the export volumes to the delivery point. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves for Poco's export pool exceeds Poco's expected long-term requirements by 28 percent. The Board's projection of productive capacity from established reserves shows that Poco can meet its average annual requirements throughout the applied-for term, except possibly in 1998. This shortfall could be met by developing some of Poco's undiscovered potential. As well, the Board notes an application for DOE/FE import authorization

has been made and that all other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contract are consistent with the proposed term of the licence. The Board is therefore satisfied that the requested licence term is appropriate.

4.7 Decision

The Board has decided to issue a gas export licence to Poco, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Chapter 5

San Diego Gas & Electric and Bow Valley Industries Ltd.

5.1 Application Summary

By application dated 22 January 1992, SDG&E and BVI applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	11 years from the date of first deliveries	
Point of Export	-	near Kingsgate, British Columbia	
Maximum Daily Quantity	-	139.5 10^3m^3	(4.9 MMcf)
Maximum Annual Quantity	-	50.9 10^6m^3	(1.8 Bcf)
Maximum Term Quantity	-	560 10^6m^3	(19.7 Bcf)
Tolerances	-	ten percent per day and two percent per year	
	-	any volumes authorized for export that are not exported during any year may be exported during the remaining term of the licence subject to the authorized maximum daily and annual volumes and tolerance.	

The gas proposed for export would be produced from pools in Alberta owned by BVI. The gas would be transported on the NOVA system for delivery to SDG&E near Coleman, Alberta. SDG&E would ship the gas through the ANG/Foothills system in Canada for export near Kingsgate, British Columbia. The gas would then flow on the pipelines of PGT, Pacific Gas & Electric Company ("PG&E") and Southern California Gas Company ("SoCalGas") before being delivered into the SDG&E system. SDG&E is an electric and gas utility serving southern California.

5.2 Gas Supply

5.2.1 Reserves

Contractually, BVI may supply the proposed export from its corporate reserves. Accordingly, no specific pools have been dedicated to the sale. BVI adopted ERCB estimates of its reserves submitted in support of this application without necessarily agreeing with the ERCB evaluation. Table 5-1 shows that the Board's reserves estimate is one percent lower than that submitted by BVI but is four percent higher than BVI's total requirements, including the proposed export volumes.

Table 5-1

Comparison of Estimates of BVI's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

BVI[1]	NEB[2]	Applied-for[3] Volume
2 682 (94.7)	2 660 (93.9)	560 (19.8)

1. As of 1 July 1992. In addition to the established gas reserves estimate, BVI also submitted an estimate of 989 10^6m^3 (35 Bcf) for those reserves that will be decontracted in Craigend and Ashmont. BVI also stated that it could draw upon additional reserves in Saskatchewan.
2. As of 31 December 1991.
3. This represents 22 percent of BVI's long-term total requirements of 2 558 10^6m^3 (90 Bcf).

BVI stated that the reserves submitted in support of the proposed export are not the only sources of gas supply for the export, although they are likely to be the principal source. BVI could also rely on an estimated 989 10^6m^3 (35 Bcf) of reserves in the Craigend and Ashmont Fields that would become available to BVI in about 1995 due to decontracting. BVI could also rely on substantial excess deliverability from the Hatton Field in Saskatchewan.

5.2.2 Productive Capacity

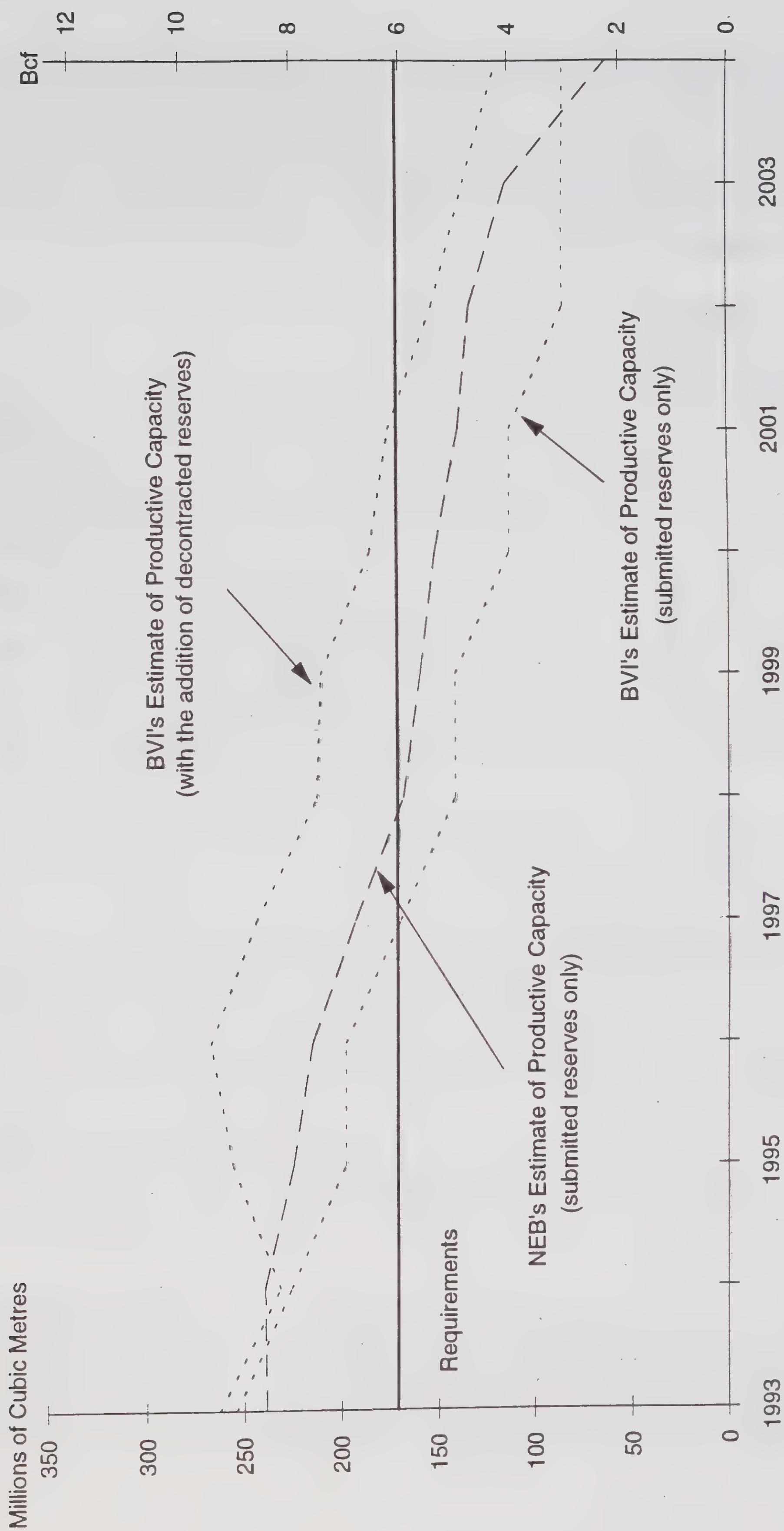
Figure 5-1 compares the Board's and BVI's projections of productive capacity with the applied-for annual export volumes. Both estimates indicate shortfalls commencing in the fourth or fifth year of the proposed 11-year export. BVI intends to backstop its deliverability with reserves from the Craigend and Ashmont Fields. Productive capacity from these decontracted reserves will extend BVI's ability to meet its commitments to about eight years. BVI will remedy the remaining shortfall with excess deliverability from the Hatton field in Saskatchewan, along with corporate reserves additions.

5.3 Transportation

BVI and NOVA signed a 15-year FS transportation contract dated 1 September 1991 for sufficient capacity for this export.

Figure 5-1

Comparison of BVI's and NEB's Estimates of Annual Productive Capacity



SDG&E executed a 15-year FS transportation contract with ANG on 31 May 1991 for a daily quantity of 1 500 10^3m^3 (53,000 MMBtu). SDG&E also signed 30-year FS transportation contracts with PGT and PG&E in 1991 and a five-year wholesale service transportation contract with SoCalGas in 1990. Service on SoCalGas after the five-year term would be available either through a negotiated contract or a CPUC approved tariff. These contracts are for a capacity sufficient for SDG&E to transport the volumes contracted from BVI, CHML, Husky and Summit.

5.4 Markets and Sales Contracts

The following discussion of SDG&E's market applies to the applications made jointly by SDG&E with each of BVI, CHML, Husky and Summit.

SDG&E is the third largest electric and gas utility in California, serving the San Diego and Orange Counties in southern California. SDG&E provides gas sales and transportation service to its core and non-core customers. Presently, these customers represent slightly over 60 percent of SDG&E's total annual gas requirements. The remainder is gas for utility electric generation ("UEG"). In 1991, SDG&E had approximately 682,000 core and 124 non-core gas customers and a million electricity customers. SDG&E's total 1991 gas sales were 2 979 10^6m^3 (105.2 Bcf).

Over the 1987-91 period, SDG&E's market has experienced an average 0.28 percent per annum reduction of its total gas demand. This reduction reflects a decrease in the non-core demand caused by the recent recession, state regulatory changes and warmer weather patterns. However, SDG&E's core market demand over the same period increased at an average of three percent annually. SDG&E attributes the growth in its core market demand to population growth due to the desirable climate, the employment opportunities offered by San Diego's diversified economy and to legislative and regulatory initiatives designed to reduce combustion emissions.

SDG&E produced a gas supply/demand forecast that projects an increase in total demand of 50 percent, equivalent to 1 458.3 10^6m^3 (51.5 Bcf), for the period 1992 to 2002. SDG&E projected that its UEG gas consumption would increase by 991 10^6m^3 (35 Bcf) over the next ten years to meet an anticipated 30 percent increase in electricity demand.

Since SDG&E has not had access to sufficient long-term transportation capacity on interstate pipelines into California, it has been purchasing its gas requirements on a short-term basis. This gas is sourced from Texas, Oklahoma and New Mexico and transported through the El Paso Natural Gas Company ("El Paso") and Transwestern Pipeline Company ("Transwestern") pipelines via the SoCalGas system. Periodically, SDG&E has purchased Canadian gas when transportation was available.

SDG&E stated that the applied-for volumes would help diversify its gas supply portfolio and assist it in meeting its future baseload energy requirements. SDG&E estimated that the applied-for volumes would represent 18 percent of SDG&E's total requirements, decreasing to 15 percent by 2002. SDG&E anticipates that the volumes purchased from BVI would be taken at a 90 percent load factor.

SDG&E and BVI executed a gas sales contract dated 12 March 1991. The primary term of the contract extends for 11 years from the commencement of firm deliveries. Subject to regulatory approvals, the contract may be extended annually thereafter. Commencement of firm deliveries is defined as the date upon which firm transportation service is available on NOVA, ANG/Foothills, PGT, PG&E and SoCalGas for this export or the date upon which all regulatory authorizations are obtained. The contract term is expected to commence by 31 December 1994.

The contract provides for an MDQ of 141 10^3m^3 (5.0 MMcf) to be delivered at Coleman, Alberta and is subject to the receipt of regulatory approvals and to the commencement of firm deliveries by 31 December 1994. SDG&E and BVI stated that the contract was negotiated at arm's length.

Under the contract, SDG&E is to nominate a Minimum Monthly Quantity ("MMQ") equal to 90 percent of the sum of the MDQs for the month. SDG&E must compensate BVI for the NOVA demand charges associated with the volumes not nominated. If SDG&E nominates less than the MMQ on average in any six consecutive month period, BVI may elect to reduce the MDQ proportionally.

The contract price equals 97 percent of SDG&E's WACOG plus SoCalGas' unit transportation cost minus SDG&E's unit transportation cost. The WACOG is the monthly weighted average cost of gas for SDG&E's firm, term and spot gas purchases through the SoCalGas, El Paso and Transwestern systems. The WACOG is determined by SDG&E based on its actual commodity and variable transportation costs. The WACOG is subject to CPUC approval.

The estimated netback price that would have been in effect under the terms of this contract at Coleman, Alberta on 1 January 1992 was $1.137/GJ ($1.197/MMBtu). Should the CPUC adopt incremental tolls for the required new compression facilities on SoCalGas, the netback price may be reduced by as much as $0.08/GJ ($0.084/MMBtu).

5.5 Status of Regulatory Authorizations and Contract Approvals

BVI applied to the ERCB for a removal permit on 18 August 1992. A decision on the application is pending. SDG&E obtained DOE/FE import authorization on 13 November 1992. All U.S. pipeline expansions are currently under construction except for some compressors to be installed between the PG&E and SoCalGas systems. The compressors were the subject of a CPUC hearing that commenced on 3 November 1992. A decision from the CPUC is pending.

5.6 Views of the Board

The Board notes that SDG&E must consistently nominate at approximately a 90 percent load factor if it is to avoid curtailment of the MDQ. The Board also recognizes that the growing SDG&E market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board is of the view that the contract price is market sensitive. As well, the Board takes comfort in SDG&E and BVI's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned by BVI, a finding of producer support is not necessary.

The Board notes that SDG&E is responsible for all transportation charges on ANG/Foothills and must compensate BVI for the NOVA demand charges associated with volumes not nominated. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales

contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's reserves estimate is approximately equal to BVI's total requirements. The Board's estimate of productive capacity indicates shortfalls commencing in the fifth year of the proposed term. However, the Board is satisfied that BVI has adequate additional reserves and deliverability to satisfy its total requirements over the proposed term. The Board also observes that the term of the gas sales contract is 11 years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume no less than the term of the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

SDG&E and BVI requested a tolerance under which any volumes authorized for export that are not exported during any year may be exported during the remaining term of the licence, subject to the authorized maximum daily and annual volumes and tolerances. The Board is not persuaded that such flexibility is warranted in the licence and notes that such volumes may be exported under short-term order.

5.7 Decision

The Board has decided to issue a gas export licence to SDG&E and BVI, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Chapter 6

San Diego Gas & Electric and Canadian Hunter Marketing Ltd.

6.1 Application Summary

By application dated 21 January 1992, SDG&E and CHML applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	ten years from the date of first deliveries
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	557.6 10^3m^3 (19.7 MMcf)
Maximum Annual Quantity	-	203.5 10^6m^3 (7.2 Bcf)
Maximum Term Quantity	-	2 035 10^6m^3 (71.8 Bcf)
Tolerances	-	ten percent per day and two percent per year
	-	any volumes authorized for export that are not exported during any year may be exported during the remaining term of the licence subject to the authorized maximum daily and annual volumes and tolerance.

The gas proposed for export would be produced by CHML's parent, Canadian Hunter Exploration Limited ("CHEL") from the Border Montney Unit B in British Columbia. The gas, which is adjacent to the Alberta border, would be transported on the NOVA system for delivery to SDG&E near Coleman, Alberta. SDG&E would ship the gas through the ANG/Foothills system in Canada for export near Kingsgate, British Columbia. The gas would then flow on the pipelines of PGT, PG&E and SoCalGas before being delivered into the SDG&E system. SDG&E is an electric and gas utility serving southern California.

6.2 Gas Supply

6.2.1 Reserves

CHML intends to supply the proposed export from CHEL's interest in the Border Montney Unit B. The technical data CHML submitted for the Border Montney Unit B indicated a reserves base of 6 202 10^6m^3 (219 Bcf) of proven reserves and 5 806 10^6m^3 (205 Bcf) of proven undeveloped reserves. Table 6-1 shows that the Board's estimate of established gas reserves dedicated to this application by CHML is three percent higher than CHML's estimate and exceeds the applied-for volume by five percent.

Table 6-1

Comparison of Estimates of CHML's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

CHML[1]	NEB[2]	Applied-for Volume
2 067 (73)	2 128 (75)	2 035 (72)

1. As of 1 January 1992. The volume committed by CHML represents less than its working interest share of 35.8 percent in the Border Montney Unit B.
2. As of 1 January 1992. This reserves estimate represents CHML's committed volume of 2 068 10^6m^3 (73 Bcf) times the ratio of the total Border Montney pool size recognized by the Board and CHML.

6.2.2 Productive Capacity

Figure 6-1 compares the Board's and CHML's projections of productive capacity to the applied-for annual volume. Both projections are generally flat and exceed requirements except for a portion of the final year of the licence term because of a significant infill drilling program in a large undeveloped reserves base. In its forecast of productive capacity, CHML has added 117 wells for a total of 172 wells producing by the year 2002. CHML also submitted a forecast of its total company productive capacity which it could use to satisfy the applied-for volumes. This forecast shows that CHEL's total company productive capacity exceeds its total long-term requirements over the applied-for term.

6.3 Transportation

CHML and NOVA signed a 15-year FS transportation contract dated 1 September 1991 for sufficient capacity for this export. Transportation arrangements downstream of the NOVA outlet are discussed in Section 5.3 of these Reasons.

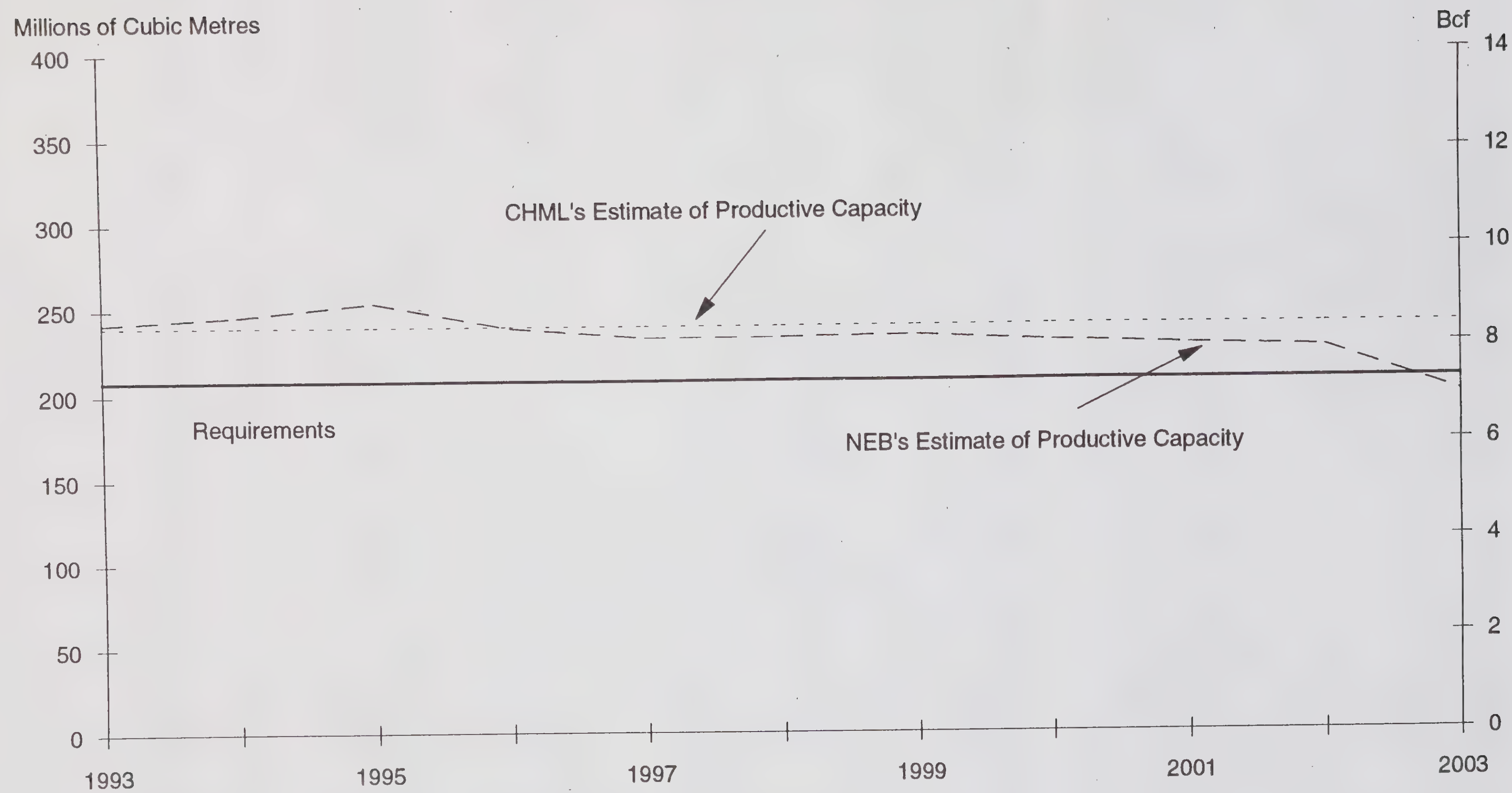
6.4 Markets and Sales Contracts

A discussion of the SDG&E market is presented in Section 5.4 of these Reasons.

SDG&E and CHML executed a gas sales contract dated 12 March 1991. The primary term of the contract extends for ten years from the commencement of firm deliveries. Subject to regulatory approvals, the contract may be extended annually thereafter. Commencement of firm deliveries

Figure 6-1

Comparison of CHML's and NEB's Estimates of Annual Productive Capacity



is defined as the date upon which firm transportation service is available on NOVA, ANG/Foothills, PGT, PG&E and SoCalGas for this export or the date upon which all regulatory authorizations are obtained. The contract term is expected to commence by 31 December 1994. SDG&E and CHML expected the load factor to average 90 percent over the contract term.

The contract provides for an MDQ of 563.5 10^3m^3 (20.0 MMcf) to be delivered at Coleman, Alberta and is subject to the receipt of regulatory approvals and to the commencement of firm deliveries by 31 December 1994. SDG&E and CHML stated that the contract was negotiated at arm's length.

Under the contract, SDG&E is to nominate an MMQ equal to 95 percent of the sum of the MDQs for the month. If SDG&E nominates less than the MMQ in two consecutive months, then it must pay a gas inventory charge ("GIC") of $U.S. 0.29/GJ ($U.S. 0.30/MMBtu) on the deficient volume. In addition, SDG&E must compensate CHML for the NOVA demand charges associated with the volumes not nominated. SDG&E can recover up to half of the GIC payments by nominating volumes in excess of the MMQ over the remaining contract term.

The contract price is equal to SDG&E's WACOG, as described in Section 5.4 of these Reasons, plus SoCalGas' unit transportation cost minus SDG&E's unit transportation cost and $U.S. 0.05/GJ ($U.S. 0.05/MMBtu).

The estimated netback price that would have been in effect under the terms of this contract at Coleman, Alberta on 1 January 1992 was $1.149/GJ ($1.209/MMBtu). Should the CPUC adopt incremental tolls for the required new compression facilities on SoCalGas, the netback price may be reduced by as much as $0.08/GJ ($0.084/MMBtu).

6.5 Status of Regulatory Authorizations and Contract Approvals

CHML applied to the EMPR for a removal certificate on 24 July 1992. A decision on the application is pending. DOE/FE and facility expansion authorizations are discussed in Section 5.5 of these Reasons.

6.6 Views of the Board

The Board notes that SDG&E must nominate 95 percent of the MDQ if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing SDG&E market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board is of the view that the contract price is market sensitive. As well, the Board takes comfort in SDG&E and CHML's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

Producer support was demonstrated by the fact that CHML, as agent for CHEL, executed the gas sales contract with SDG&E.

The Board notes that SDG&E is responsible for all transportation charges on ANG/Foothills and must compensate CHML for the NOVA demand charges associated with volumes not nominated. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of submitted reserves exceeds the applied-for volumes. Productive capacity is expected to be maintained throughout the majority of the applied-for term by a significant in-fill drilling program. The Board is satisfied that CHML can meet its requirements throughout the applied-for term from the submitted supply, and could mitigate any potential shortfalls from other corporate reserves. The Board also observes that the term of the gas sales contract is ten years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume no less than the term of the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

SDG&E and CHML requested a tolerance under which any volumes authorized for export that are not exported during any year may be exported during the remaining term of the licence, subject to the authorized maximum daily and annual volumes and tolerances. The Board is not persuaded that such flexibility is warranted in the licence and notes that such volumes may be exported under short-term order.

6.7 Decision

The Board has decided to issue a gas export licence to SDG&E and CHML, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

San Diego Gas & Electric and Husky Oil Operations Ltd.

7.1 Application Summary

By application dated 22 January 1992, SDG&E and Husky applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	ten years from the first date of deliveries
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	609.9 10^3m^3 (21.7 MMcf)
Maximum Annual Quantity	-	222.6 10^6m^3 (7.9 Bcf)
Maximum Term Quantity	-	2 226 10^6m^3 (79.1 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas proposed for export would be produced from pools in Alberta owned by Husky. The gas would be transported on the NOVA system for delivery to SDG&E near Coleman, Alberta. SDG&E would ship the gas through the ANG/Foothills system in Canada for export near Kingsgate, British Columbia. The gas would then flow on the pipelines of PGT, PG&E and SoCalGas before being delivered into the SDG&E system. SDG&E is an electric and gas utility serving southern California.

7.2 Gas Supply

7.2.1 Reserves

Husky intends to supply the proposed export from the undedicated Alberta corporate reserves, including its Caroline and Karr properties, that it submitted to the Board during the GH-4-92 TransCanada 1993-94 facilities proceeding. Husky adopted ERCB estimates of its reserves for the purposes of its submission. Table 7-1 shows that the Board's estimate of established gas reserves is one percent lower than Husky's, but exceeds Husky's estimated long-term commitments, including the proposed export by 35 percent.

7.2.2 Productive Capacity

Figure 7-1 compares the Board's and Husky's projections of productive capacity with Husky's total requirements, including the applied-for volumes. Both projections show that Husky's supply pool is expected to exceed total requirements throughout the term of the proposed export.

Table 7-1

Comparison of Estimates of Husky's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Husky[1]	**NEB**[1]	**Applied-for**[2] **Volume**
17 811 (628.7)	17 163 (605.9)	2 226 (78.6)

1. As of 31 December 1991.
2. This represents 17 percent of Husky's estimated short and long-term commitments of 13 090 10^6m^3 (462 Bcf) for its Alberta-sourced gas.

7.3 Transportation

Husky and NOVA signed a 15-year FS transportation contract dated 1 September 1991 for sufficient capacity for this export. Transportation arrangements downstream of the NOVA outlet are discussed in Section 5.3 of these Reasons.

7.4 Markets and Sales Contracts

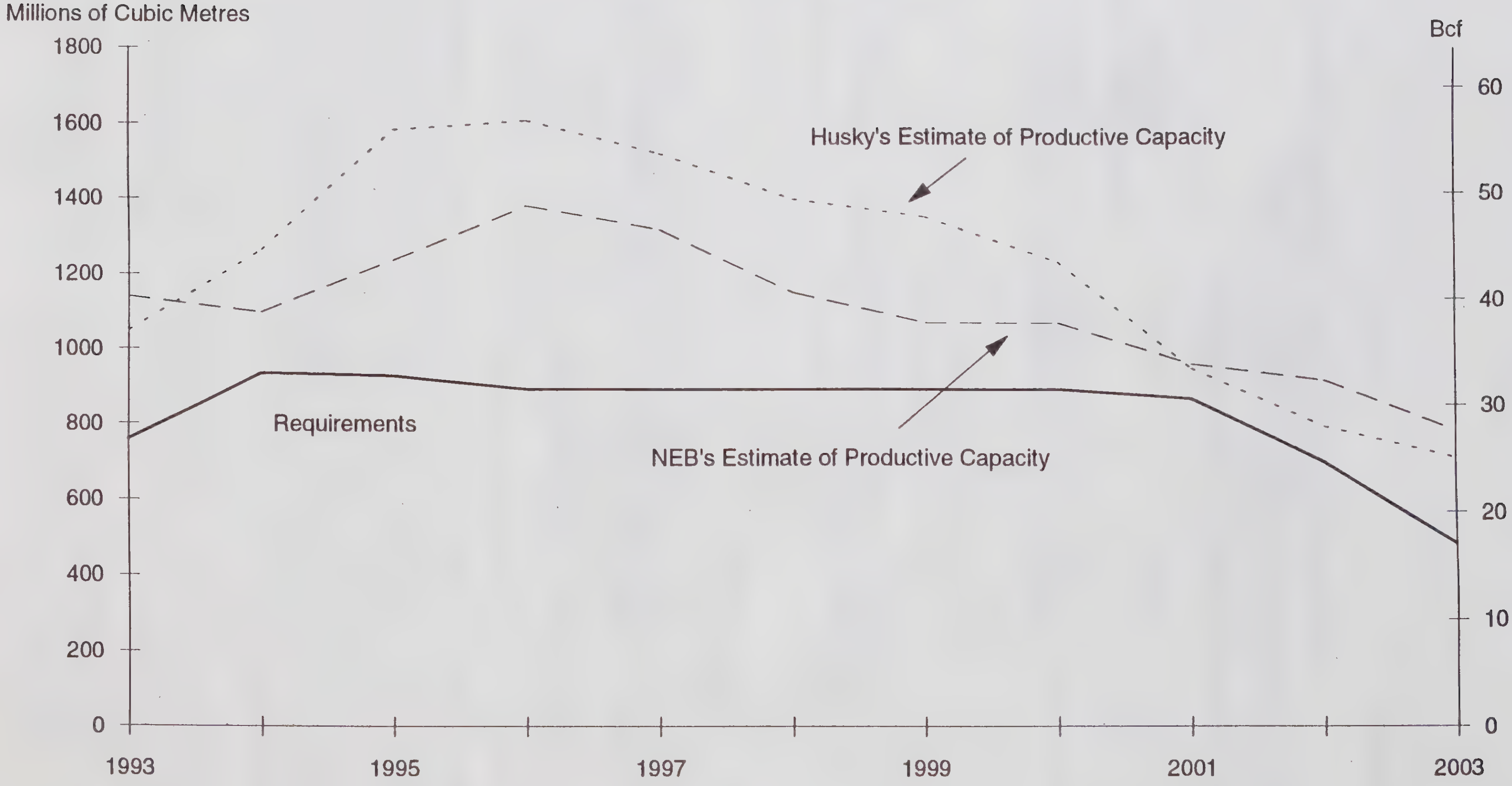
A discussion of the SDG&E market is presented in Section 5.4 these Reasons.

SDG&E and Husky executed a gas sales contract dated 12 March 1991, as amended. The primary term of the contract extends for ten years from the commencement of firm deliveries. Subject to regulatory approvals, the contract may be extended annually up to a maximum of five years. Commencement of firm deliveries is defined as the date upon which firm transportation service is available on NOVA, ANG/Foothills, PGT, PG&E and SoCalGas for this export or the date upon which all regulatory authorizations are obtained. The contract term is expected to commence by 31 December 1994. SDG&E and Husky expected the load factor to average 90 percent over the contract term.

The contract provides for an MDQ of 616.52 10^3m^3 (21.9 MMcf) to be delivered at Coleman, Alberta and is subject to the receipt of regulatory approvals and to the commencement of firm deliveries by 1 November 1994. SDG&E and Husky stated that the contract was negotiated at arm's length.

Figure 7-1

Comparison of Husky's and NEB's Estimates of Annual Productive Capacity



Under the contract, SDG&E is to nominate an MMQ equal to 90 percent of the sum of the MDQs for the month. If SDG&E nominates less than the MMQ in two consecutive months, then it must pay a GIC equal to 20 percent of the difference between the contract price and the NOVA charges on the deficient volume. In addition, SDG&E must compensate Husky for the NOVA demand charges associated with the volumes not nominated. SDG&E can recover up to half of the GIC payments by nominating volumes in excess of the MMQ in a subsequent 12-month period.

The contract price equals 97 percent of SDG&E's WACOG, as described in Section 5.4 of these Reasons, plus SoCalGas' unit transportation cost minus SDG&E's unit transportation cost.

The estimated netback price that would have been in effect under the terms of this contract at Coleman, Alberta on 1 January 1992 was $1.137/GJ ($1.197/MMBtu). Should the CPUC adopt incremental tolls for the required new compression facilities on SoCalGas, the netback price may be reduced by as much as $0.08/GJ ($0.084/MMBtu).

7.5 Status of Regulatory Authorizations and Contract Approvals

Husky applied to the ERCB on 16 October 1992 to amend its removal permit. A decision on the application is pending. DOE/FE and facility expansion authorizations are discussed in Section 5.5 of these Reasons.

7.6 Views of the Board

The Board notes that SDG&E must nominate 90 percent of the MDQ if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing SDG&E market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board is of the view that the contract price is market sensitive. As well, the Board takes comfort in SDG&E and Husky's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned by Husky, a finding of producer support is not necessary.

The Board notes that SDG&E is responsible for all transportation charges on ANG/Foothills and must compensate Husky for the NOVA demand charges associated with volumes not nominated. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of Husky's reserves exceeds Husky's total estimated long-term commitments. Similarly, the Board's projection of productive capacity shows that Husky can satisfy its total requirements throughout the term of the proposed export. The Board also observes that the term of the gas sales contract is ten years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years.

The regulatory authorizations either applied-for or received are for a term and volume no less than the term of the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

7.7 Decision

The Board has decided to issue a gas export licence to SDG&E and Husky, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

San Diego Gas & Electric and Summit Resources Limited

8.1 Application Summary

By application dated 22 January 1992, SDG&E and Summit applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	eight years from the date of first deliveries
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	195.1 10^3m^3 (6.9 MMcf)
Maximum Annual Quantity	-	71.2 10^6m^3 (2.5 Bcf)
Maximum Term Quantity	-	570 10^6m^3 (20.1 Bcf)
Tolerances	-	ten percent per day and two percent per year
	-	any volumes authorized for export that are not exported during any year may be exported during the remaining term of the licence subject to the authorized maximum daily and annual volumes and tolerances.

The gas proposed for export would be produced from pools in Alberta owned by Summit. The gas would be transported on the NOVA system for delivery to SDG&E near Coleman, Alberta. SDG&E would ship the gas through the ANG/Foothills system in Canada for export near Kingsgate, British Columbia. The gas would then flow on the pipelines of PGT, PG&E and SoCalGas before being delivered into the SDG&E system. SDG&E is an electric and gas utility serving southern California.

8.2 Gas Supply

8.2.1 Reserves

Summit intends to supply the proposed export from uncontracted reserves submitted in the application. Table 8-1 shows that the Board's estimate of Summit's established gas reserves is 14 percent higher than Summit's and exceeds the applied-for volume by 39 percent. The Board's estimate of reserves is higher than that submitted by Summit due primarily to a difference in the interpretation of reservoir performance charts.

Summit provided estimates of development reserves for 13 sections of land in the Chain and Craigmyle areas with a probability of success ranging from 25 to 50 percent. Summit classified its development reserves as those reserves on its lands that are gas prone based on geophysical,

Table 8-1

Comparison of Estimates of Summit's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Summit[1]	NEB[2]	Applied-for Volume
700 (24.7)	798 (28.2)	570 (20.1)

1. As of 1 January 1992. In addition to the established gas reserves estimate, Summit also submitted an estimate of 157 10^6m^3 (5.5 Bcf) as its working interest share of development reserves.
2. As of 1 January 1992.

geological and engineering data. Summit has not developed the lands to date because there was no contractual requirement for their gas deliverability. The Board has reviewed Summit's development reserves and generally agrees with Summit's assessment.

8.2.2 Productive Capacity

Figure 8-1 compares the Board's and Summit's projections of productive capacity to the applied-for annual volume. The requirements represent the applied-for annual volumes with a 100 percent load factor.

The Board's projection suggests that Summit can meet its annual requirements for four and one-half to five years of the eight-year applied-for term. Summit's development acreage and corporate reserves additions are expected to mitigate the projected deliverability shortfall.

8.3 Transportation

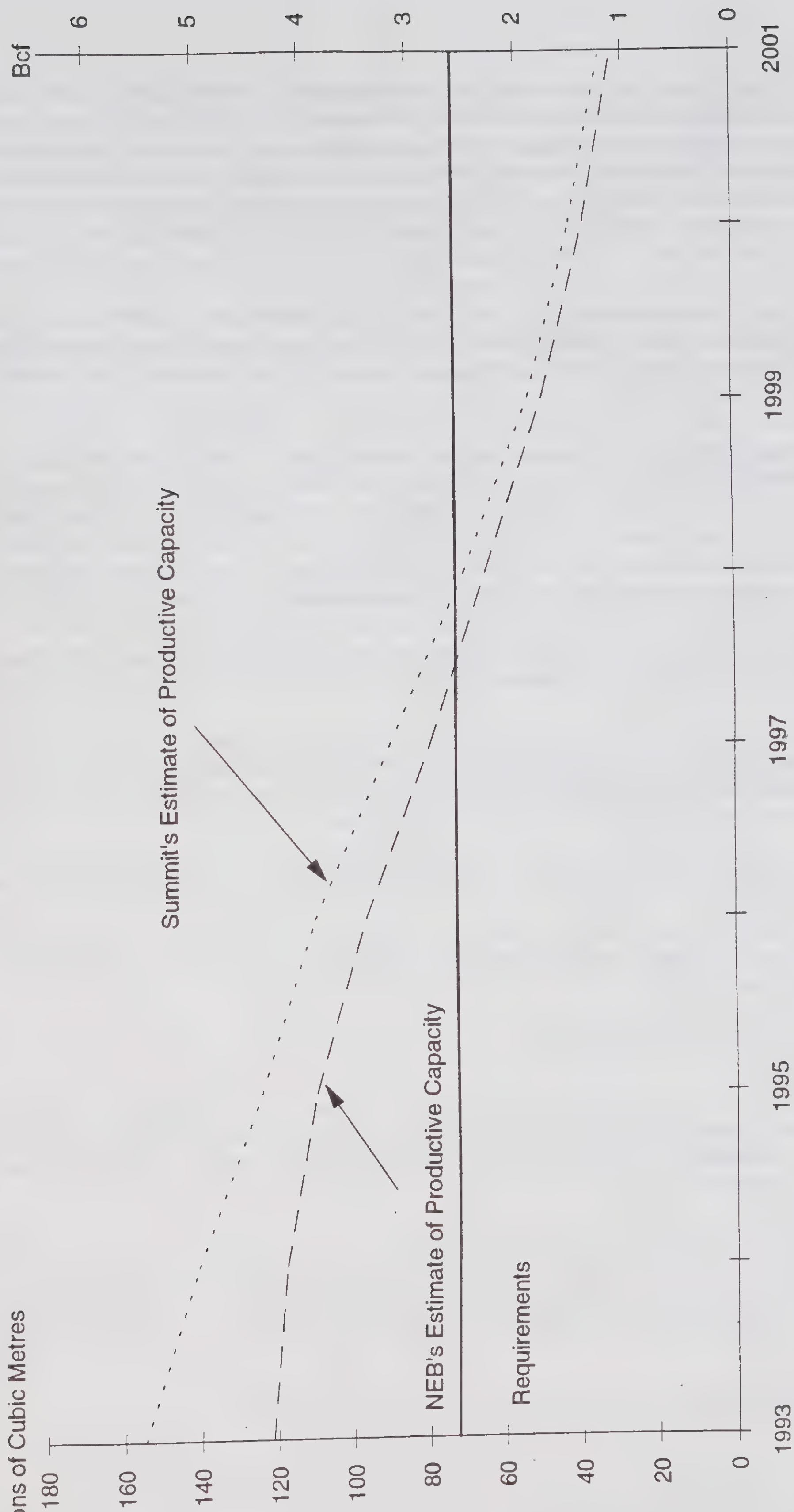
Summit and NOVA signed a 15-year FS transportation contract dated 1 September 1991 for sufficient capacity for this export. Transportation arrangements downstream of the NOVA outlet are discussed in Section 5.3 of these Reasons.

8.4 Markets and Sales Contracts

A discussion of the SDG&E market is presented in Section 5.4 of these Reasons.

Figure 8-1

Comparison of Summit's and NEB's Estimates of Annual Productive Capacity



SDG&E and Summit executed a gas sales contract dated 12 March 1991. The primary term of the contract extends for eight years from the commencement of firm deliveries. Subject to regulatory approvals, the contract may be extended annually thereafter. Commencement of firm deliveries is defined as the date upon which firm transportation service is available on NOVA, ANG/Foothills, PGT, PG&E and SoCalGas for this export or the date upon which all regulatory authorizations are obtained. The contract term is expected to commence by 31 December 1994. SDG&E and Summit expected the load factor to average 90 percent over the contract term.

The contract provides for an MDQ of 197.2 10^3m^3 (7.0 MMcf) to be delivered at Coleman, Alberta and is subject to the receipt of regulatory approvals and commencement of firm deliveries by 31 December 1994. SDG&E and Summit stated that the contract was negotiated at arm's length.

Under the contract, SDG&E is to nominate an MMQ equal to 90 percent of the sum of the MDQs for the month. If SDG&E nominates less than the MMQ in two consecutive months, then it must pay a GIC of $U.S. 0.29/GJ ($U.S. 0.30/MMBtu) on the deficient volume. In addition, SDG&E must compensate Summit for the NOVA demand charges associated with the volumes not nominated. SDG&E can recover up to 30 percent of the GIC payments by nominating volumes in excess of the MMQ in a subsequent six-month period.

The contract price equals 97 percent of SDG&E's WACOG, as described in Section 5.4 of these Reasons, plus SoCalGas' unit transportation cost minus SDG&E's unit transportation cost.

The estimated netback price that would have been in effect under the terms of this contract at Coleman, Alberta on 1 January 1992 was $1.137/GJ ($1.197/MMBtu). Should the CPUC adopt incremental tolls for the required new compression facilities on SoCalGas, the netback price may be reduced by as much as $0.08/GJ ($0.084/MMBtu).

8.5 Status of Regulatory Authorizations and Contract Approvals

Summit applied to the ERCB for a removal permit on 15 January 1992. A decision on the application is pending. DOE/FE and facility expansion authorizations are discussed in Section 5.5 of these Reasons.

8.6 Views of the Board

The Board notes that SDG&E must nominate 90 percent of the MDQ if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing SDG&E market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board is of the view that the contract price is market sensitive. As well, the Board takes comfort in SDG&E and Summit's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned by Summit, a finding of producer support is not necessary.

The Board notes that SDG&E is responsible for all transportation charges on ANG/Foothills and must compensate Summit for the NOVA demand charges associated with volumes not nominated. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves exceeds Summit's requirements by 40 percent. The Board's estimate of productive capacity exceeds Summit's requirements for the majority of the applied-for term. The Board is satisfied that Summit can meet its requirements throughout the applied-for term by adding productive capacity from other existing reserves in its corporate portfolio and by developing new reserves. The Board also observes that the term of the gas sales contract is eight years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume no less than the term of the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

SDG&E and Summit requested a tolerance under which any volumes authorized for export that are not exported during any year may be exported during the remaining term of the licence, subject to the authorized maximum daily and annual volumes and tolerances. The Board is not persuaded that such flexibility is warranted in the licence and notes that such volumes may be exported under short-term order.

8.7 Decision

The Board has decided to issue a gas export licence to SDG&E and Summit, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Southern California Edison Company and AEC Oil and Gas Company a division of Alberta Energy Company Ltd.

9.1 Application Summary

By application dated 17 January 1991, Edison and AEC applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 November 1993 or the date when firm transportation is available for the full volume on the pipeline systems of NOVA, ANG/Foothills, PGT, PG&E and SoCalGas, for a term of 15 years
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	1 445 10^3m^3 (51.0 MMcf)
Maximum Annual Quantity	-	529 10^6m^3 (18.7 Bcf)
Maximum Term Quantity	-	7 913 10^6m^3 (279.4 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas proposed for export would be produced in Alberta from reserves either owned by or under contract to AEC. The gas would be transported in Canada on NOVA and ANG/Foothills to the international border near Kingsgate, British Columbia. In the U.S., the gas would flow through the PGT, PG&E and SoCalGas systems for delivery to Edison. Edison is an electric utility operating in central and southern California.

9.2 Gas Supply

9.2.1 Supply Contracts

AEC intends to supply the proposed export from corporate uncontracted reserves and with gas purchased from Pan-Alberta Gas Ltd. ("Pan-Alberta"). Accordingly, no specific pools have been contractually dedicated to the sale. Under the provisions of the contract, AEC warrants to deliver the gas nominated by Edison.

AEC and Pan-Alberta have executed a contract for Pan-Alberta to provide 586 $10^3m^3/d$ (20.7 MMcfd) over 15 years, which is 40 percent of the requirements. AEC has agreed to use every reasonable effort to make up for any failure of delivery by Pan-Alberta. In the event that AEC is unable to make up any such deficiency, Pan-Alberta will indemnify AEC for any penalty

Table 9-1

Comparison of Estimates of Producers' Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Company	Supplier's Estimate	NEB	Applied-for Volume
AEC	14 755 (520.9)	13 387.7 (472.6)	N/A
Pan-Alberta	13 138[1] (464.1)	11 981[1] (423.1)	N/A
Total	27 893 (985.0)	25 368 (895.7)	7 913[2] (279.4)

1. as of 1 January 1992. Approximately 1 900 10^6m^3 (67 Bcf) will be produced from these reserves over the period 1 January 1992 to 1 November 1993.
2. These volumes represent only a portion of the suppliers' total commitments which must be supplied from these reserves. Total requirements are estimated to be 7 950 10^6m^3 (280.6 Bcf) for AEC and 3 210 10^6m^3 (113.4 Bcf) for Pan-Alberta.

resulting from its inability to deliver. Pan-Alberta has not dedicated specific gas pools to AEC in this contract.

9.2.2 Reserves

The reserves submitted by AEC in support of this application are the same as those provided for the WWP application. A description of AEC's supply is provided in Section 3.2 of these Reasons.

Pan-Alberta has submitted its estimate of reserves for the pools from which it intends to provide a gas supply for ANG/PGT expansion sales, including this sale to AEC. Pan-Alberta has stated that it intends to dedicate these reserves to the expansion sales.

Table 9-1 shows that the Board's estimate of Pan-Alberta's gas supply is nine percent lower than Pan-Alberta's, and the combined reserves of AEC and Pan-Alberta are three times larger than the applied-for volume. As described in Section 3.2.3, AEC is also using this supply for other requirements.

9.2.3 Productive Capacity

A description of AEC's productive capacity is provided in Section 3.2.3 of these Reasons.

The Board has accepted Pan-Alberta's assessment of productive capacity, which indicates more than adequate gas supply to meet the applied-for volume over the proposed export term. Pan-Alberta's projection shows that initial productive capacity is approximately eight times greater than its commitment to AEC. The Edison requirement is currently the only one Pan-Alberta has shown against its submitted supply.

9.3 Transportation

AEC has applied to NOVA for sufficient firm transportation delivery service to the Alberta/British Columbia border near Coleman, Alberta effective 1 November 1993.

Edison executed a 15-year FS transportation contract with ANG, dated 31 May 1991, for service from Coleman to the international border, at Kingsgate. Edison has also executed 30-year FS transportation agreements with PGT and PG&E to deliver the gas from the international border to the SoCalGas interconnect at Kern River Station, California. Service on SoCalGas will be available under a tariff approved by the CPUC. These agreements are for a capacity sufficient for Edison to transport the volumes contracted from AEC, Imperial Oil, Shell and Western Gas.

9.4 Markets and Sales Contracts

The following discussion of Edison's market applies to the applications made jointly by Edison with each of AEC, Imperial Oil, Shell and Western Gas.

Edison is the second largest electric utility operating in the U.S., providing electric service to approximately 4.1 million customers over central and southern California. Its annual gas requirements are projected to increase from 4 960 10^6m^3 (175 Bcf) to 7 054 10^6m^3 (249 Bcf) during the period 1993 to 2010.

Edison's generating stations will use the proposed export volumes in the production of electricity. Natural gas is the preferred fuel for use in Edison's oil/gas generating stations. Air quality restrictions, environmental concerns and the generally lower cost of gas have caused Edison to minimize its use of low sulphur fuel oil.

Edison's current source of gas supply is primarily from the U.S. southwest. Since FS transportation has generally not been available, Edison relies on interruptible service. Accordingly, Edison makes its gas purchases primarily on the spot market or on a short-term basis. However, Edison's interruptible transportation service leaves it susceptible to curtailment. During one 18-month period, Edison claimed that its transportation service was curtailed, either wholly or partially, approximately 80 percent of the time.

The Canadian gas purchases will provide a diversification in the sources of supply available to Edison as Edison currently has no direct access to Canadian gas. The purchases will constitute approximately 40 percent of Edison's gas requirements. Edison expects the proposed exports to operate at or near a 100 percent load factor as it intends to use the gas for baseload electricity production.

AEC and Edison executed a gas sales contract dated 18 December 1990. The contract term begins with the commencement of firm deliveries and continues for 15 years. Firm deliveries are

expected to commence on 1 November 1993. Unless terminated on 12-months' notice, the contract is extended annually subject to regulatory approvals. The contract provides for an MDQ of 1 466 10^3m^3 (52,565 MMBtu or 51.8 MMcf) to be delivered at the Alberta/British Columbia border. AEC and Edison stated that the contract was negotiated at arm's length.

The contract establishes a Base Quantity ("BQ") that is 70 percent of the MDQ. The BQ is priced for a contract year based on Edison's WACOG ("EACOG") for the preceding year, adjusted through annual negotiation of a factor ("EACOG Multiplier"). The EACOG includes Edison's purchases of spot, short and long-term gas from all sources less transportation charges on PG&E and SoCalGas. If the negotiations of the EACOG Multiplier are unsuccessful, the BQ price for that contract year will be the EACOG of the prior year multiplied by an Adjustment Factor ("AF"). The AF is the quotient of EACOG monthly rates for the previous month and the corresponding month of the previous year.

Should the average BQ price, over a three-year period, be 20 percent more or less than the WACOG paid by other privately-owned California gas and/or electric utilities, the price paid for BQ gas for a contract year will be the previous year's WACOG price, plus or minus 20 percent, multiplied by an annually negotiated factor ("WACOG Multiplier"). If negotiations are unsuccessful, an AF will be determined and applied. The WACOG will be used to determine the BQ price until the three-year average EACOG price falls within 20 percent of the WACOG. The BQ price will then be determined using the EACOG.

The quantity, price and other commercial terms for the Additional Quantities ("AQ") of up to 30 percent of the MDQ will be negotiated annually. If negotiations are unsuccessful, AEC is not obligated to sell and Edison is not obligated to buy the AQ. AEC and Edison will each bear their respective unused transportation costs.

Edison is obligated to nominate an MMQ that is 70 percent of the sum of MDQ's for each day of the month. Edison must pay a deficiency charge equal to 20 percent of the BQ price less transportation charges downstream of the Alberta/British Columbia border on the difference between actual nominations and the MMQ.

The estimated netback price that would have been in effect under the terms of this contract at the delivery point on 1 January 1992 was \$1.64/GJ (\$1.73/MMBtu) assuming incremental tolls on PGT and PG&E. Edison stated it would be responsible for incremental tolls applied to the required new compression facilities on SoCalGas.

9.5 Status of Regulatory Authorizations and Contract Approvals

AEC applied to the ERCB for a gas removal permit in May 1992. A decision on the application is pending. For its share of the gas supply, Pan-Alberta holds Alberta removal permit GR87-236, as amended, which expires on 31 October 2003. Pan-Alberta will apply to the ERCB in the future to extend the term. Pan-Alberta received a finding of producer support from the Alberta Petroleum Marketing Commission ("APMC") on 3 December 1992.

An application to the DOE/FE for long-term import authorization was filed by Edison in October 1992. A decision on the application is pending. Edison currently has import authorization for two years following first deliveries.

All U.S. pipeline expansions are currently under construction except for some compressors to be installed between the PG&E and SoCalGas systems. The compressors were the subject of a CPUC hearing that commenced on 3 November 1992. A decision from the CPUC is pending.

9.6 Views of the Board

The Board notes that Edison is obligated to make minimum monthly gas nominations if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing Edison market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board observes that the contract price is market sensitive as it is negotiated annually. As well, the Board takes comfort in Edison and AEC's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contracts will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

A finding of producer support is not necessary for the portion of the gas supply owned by AEC. Pan-Alberta has obtained a finding of producer support from the APMC for its share of the gas supply.

The Board notes that Edison is responsible for transportation charges on ANG/Foothills. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of AEC's and Pan-Alberta's reserves exceeds the total requirements for those reserves. The Board's projection of AEC's productive capacity shows some minor shortfalls in the early part of the applied-for term. However, the Board is satisfied that AEC can meet its requirements by drawing on undedicated gas it currently has in its storage facilities. The Board has accepted Pan-Alberta's forecast of productive capacity, which exceeds the current long-term commitments. The Board also observes that the term of the gas sales contract is 15 years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume commensurate with the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

9.7 Decision

The Board has decided to issue a gas export licence to Edison and AEC, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Southern California Edison Company and Imperial Oil Resources Limited

10.1 Application Summary

By application dated 28 December 1990, Edison and Imperial Oil applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 November 1993 or the date when firm transportation is available for the full volume on the pipeline systems of NOVA, ANG/Foothills, PGT, PG&E and SoCalGas, for a term of 15 years
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	1 445 10^3m^3 (51.0 MMcf)
Maximum Annual Quantity	-	529 10^6m^3 (18.7 Bcf)
Maximum Term Quantity	-	7 913 10^6m^3 (279.4 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas proposed for export would be produced in Alberta from reserves owned or controlled by Imperial Oil. The gas would be transported in Canada on NOVA and ANG/Foothills to the international border near Kingsgate, British Columbia. In the U.S., the gas would flow through the PGT, PG&E and SoCalGas systems for delivery to Edison. Edison is an electric utility operating in central and southern California.

10.2 Gas Supply

10.2.1 Supply Contracts

Contractually, Imperial Oil may supply the proposed export from its corporate uncontracted reserves. Accordingly, no specific pools have been dedicated to the sale.

Imperial Oil has also executed four gas supply contracts of varying terms with the following six producers: Hillcrest Resources Ltd., Novalta Resources Inc., Petrorep (Canada) Ltd., and an aggregated group of Shunda Energy Corporation, Northern Development Company Limited and Wintershall Oil of Canada Ltd. These contracts constitute approximately five percent of Imperial Oil's uncontracted supply.

Table 10-1

Comparison of Estimates of Imperial Oil's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Imperial Oil[1]	NEB[2]	Applied-for[3] Volume
29 766 (1 051)	30 294 (1 069)	7 913 (279)

1. As of 30 June 1992.
2. As of 31 December 1991.
3. This represents 45 percent of Imperial Oil's total long-term requirements of 17 411 10^6m^3 (615 Bcf).

10.2.2 Reserves

Imperial Oil submitted ERCB estimates of reserves for its own pools. Table 10-1 shows the Board's estimate of Imperial Oil's reserves is two percent higher than that submitted by Imperial Oil and is 74 percent higher than Imperial Oil's total long-term requirements, including the proposed export volumes.

10.2.3 Productive Capacity

Figure 10-1 compares the Board's and Imperial Oil's projections of productive capacity with Imperial Oil's total long-term requirements.

Both projections indicate adequate productive capacity throughout the proposed export term. Productive capacity is expected to be sustained over the licence term from numerous available unconnected pools.

10.3 Transportation

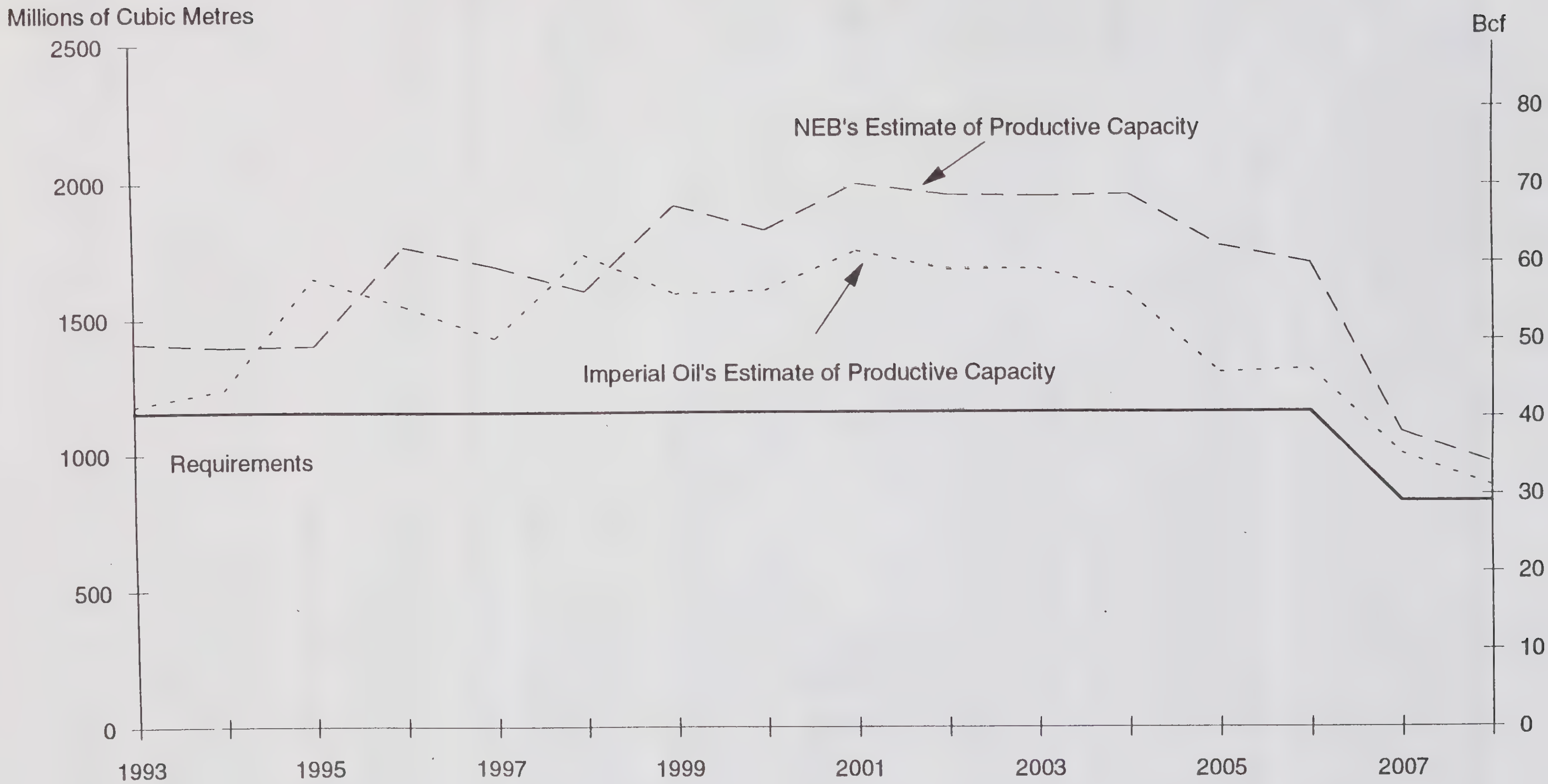
Imperial Oil has arranged for sufficient firm transportation delivery service on NOVA to the Alberta/British Columbia border near Coleman, Alberta. Edison's transportation arrangements downstream of the NOVA outlet are discussed in Section 9.3 of these Reasons.

10.4 Markets and Sales Contracts

A discussion of the Edison market is presented in Section 9.4 of these Reasons.

Figure 10-1

Comparison of Imperial Oil's and NEB's Estimates of Annual Productive Capacity



Imperial Oil and Edison executed a gas sales contract dated 18 December 1990. The contract term begins with the commencement of firm deliveries and continues for 15 years. Firm deliveries are expected to commence on 1 November 1993. Imperial Oil and Edison stated that the contract was negotiated at arm's length. Unless terminated on 12-months' notice, the contract is extended annually subject to regulatory approvals. The contract provides for an MDQ of 1 466 10^3m^3 (52,565 MMBtu or 51.8 MMcf) to be delivered at the Alberta/British Columbia border.

The BQ under the contract is 50 percent of the MDQ. The BQ is priced for a contract year based on the EACOG for the preceding year, adjusted through annual negotiation of the EACOG Multiplier. If the negotiations of the EACOG Multiplier are unsuccessful, the BQ price for that contract year will be the EACOG of the prior year multiplied by the AF.

Should the average BQ price, over a three-year period, be 15 percent more or less than the WACOG paid by other privately-owned California gas and/or electric utilities, the price paid for BQ gas for a contract year will be the previous year's WACOG price, plus or minus 15 percent, multiplied by the WACOG Multiplier. If negotiations are unsuccessful, an AF will be determined and applied. The WACOG will be used to determine the BQ price until the three-year average EACOG price falls within 15 percent of the WACOG. The BQ price will then be determined using the EACOG.

The quantity, price and other commercial terms for the AQ of up to 50 percent of the MDQ will be negotiated annually. If negotiations are unsuccessful, Imperial Oil is not obligated to sell and Edison is not obligated to buy the AQ. Imperial Oil and Edison will each bear their respective unused transportation costs.

Edison is obligated to nominate an MMQ that is 50 percent of the sum of MDQ's for each day of the month. Edison must pay a deficiency charge equal to 20 percent of the BQ price less transportation charges downstream of the Alberta/British Columbia border on the difference between actual nominations and the MMQ.

The estimated netback price that would have been in effect under the terms of this contract at the delivery point on 1 January 1992 was \$1.64/GJ (\$1.73/MMBtu) assuming incremental tolls on PGT and PG&E. Edison stated it would be responsible for incremental tolls applied to the required new compression facilities on SoCalGas.

10.5 Status of Regulatory Authorizations and Contract Approvals

Imperial Oil applied to the ERCB for a gas removal permit on 8 October 1991. A decision on the application is pending. DOE/FE and facility expansion authorizations are discussed in Section 9.5 of these Reasons.

10.6 Views of the Board

The Board notes that Edison is obligated to make minimum monthly gas nominations if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing Edison market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board observes that the contract price is market sensitive as it is negotiated annually. As well, the Board takes comfort in Edison and Imperial Oil's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The

Board is thus satisfied that the sales contracts will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned by Imperial Oil, a finding of producer support is not necessary.

The Board notes that Edison is responsible for transportation charges on ANG/Foothills. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimates of reserves and productive capacity exceed Imperial Oil's total long-term requirements, including the proposed export. The Board also observes that the term of the gas sales contract is 15 years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume commensurate with the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

10.7 Decision

The Board has decided to issue a gas export licence to Edison and Imperial Oil, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Southern California Edison Company and Shell Canada Limited

11.1 Application Summary

By application dated 30 January 1991, Edison and Shell applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of the date upon which all Conditions Precedent have been satisfied or the date when firm transportation is available for the MDQ on the pipeline systems of NOVA, ANG/Foothills, PGT, PG&E and SoCalGas, for a term of 15 years
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	1 445 10^3m^3 (51.0 MMcf)
Maximum Annual Quantity	-	529 10^6m^3 (18.7 Bcf)
Maximum Term Quantity	-	7 913 10^6m^3 (279.4 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas proposed for export would be produced from pools in Alberta owned by or contracted to Shell. The gas would be transported in Canada on NOVA and ANG/Foothills to the international border near Kingsgate, British Columbia. In the U.S., the gas would flow through the PGT, PG&E and SoCalGas systems for delivery to Edison. Edison is an electric utility operating in central and southern California.

11.2 Gas Supply

In support of its application, Shell relied primarily upon the gas supply analysis that it provided to the Board during the GH-3-91 and GH-5-92 proceedings. Shell submitted two additional gas pools in this proceeding as part of its corporate export supply pool. The Board based its review of Shell's pool on the Board's extensive analysis of the supply information provided in the GH-3-91 and GH-5-92 proceedings. Recognizing that Shell's reserves have remained substantially unchanged, the Board did not consider it necessary to conduct a detailed review of Shell's overall reserves; however, the Board did review the two additional pools. The Board also reviewed a revised productive capacity forecast provided during the hearing for the Limestone, Clearwater and Cordel fields. Details of the Board's earlier analyses are provided in the GH-3-91 and GH-5-92 Reasons for Decision.

Table 11-1

Comparison of Estimates of Shell's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Shell[1]	**NEB**[1]	**Applied-for**[2] **Volume**
43 352 (1,531)	41 802 (1,476)	7 913 (279)

1. as of 1 January, 1992. This supply includes 1 642 10^6m^3 (58 Bcf) of purchased gas.
2. These volumes represent only a portion of Shell's total commitments that must be supplied from these reserves. Shell's total commitments, including the applied-for volumes, are 38 206 10^6m^3 (1,349 Bcf).

11.2.1 Supply Contracts

Shell intends to supply the majority of the proposed export from corporate uncontracted reserves. Modest amounts of gas will be purchased from other producers. Accordingly, no specific pools have been contractually dedicated to the sale.

Shell has not executed any additional gas purchase contracts with other producers since the GH-5-92 proceedings and thus did not submit any gas purchase contracts in these proceedings.

11.2.2 Reserves

Table 11-1 shows that the Board's estimate of Shell's remaining gas reserves is four percent lower than Shell's estimate and that both estimates are approximately five times larger than the applied-for volume. The volumes under consideration for the proposed export are only a portion of Shell's total requirements. The Board's estimate of Shell's reserves is nine percent higher than Shell's total requirements.

To meet the incremental requirements of the Edison export, Shell has revised its former aggregate gas supply portfolio to include the Pekisko and Turner Valley gas pools in the Ram River area of Alberta. The Board's estimate for these two pools exceeds Shell's due to the Board's use of a larger pool area and net pay resulting from individual mapping styles. The Ram River pools constitute seven percent of the Board's estimate of Shell's remaining gas reserves.

11.2.3 Productive Capacity

Figure 11-1 compares the Board's projection of adjusted productive capacity and Shell's projection of productive capacity with Shell's total requirements, including fuel and shrinkage. Shell has estimated its annual requirements based on expected load factors.

Both projections include expected productive capacity from the Ram River development area, the purchased reserves and 566 10^3m^3 per day (20 MMcfd) that Shell can take from the Waterton area under an agreement with Alberta and Southern Gas Co. Ltd. The Board's projection also reflects substantially reduced deliverability schedules in Limestone, Clearwater and Cordel, which account for a reduced forecast compared to previous Board projections. These revised forecasts are the result of an effort by Shell, over the past year, to optimize the use of its assets. Shell stated at the hearing that its productive capacity was reduced because it was deferring development of these properties.

Shell's projection of productive capacity indicates a possible shortfall between 2000 and 2005. The Board's projection of Shell's productive capacity shows a deficiency between 1997 and 2002. Shell stated that it could alleviate any shortfalls in productive capacity by drawing gas from other properties under its control or by purchasing additional gas supplies.

11.3 Transportation

Shell has existing service agreements with NOVA for sufficient firm transportation delivery service to the Alberta/British Columbia border near Coleman, Alberta. Edison's transportation arrangements downstream of the NOVA outlet are discussed in Section 9.3 of these Reasons.

11.4 Markets and Sales Contracts

A discussion of the Edison market is presented in Section 9.4 of these Reasons.

Shell and Edison executed a gas sales contract dated 18 December 1990. The contract term begins with the commencement of firm deliveries and continues for 15 years. Firm deliveries are expected to commence on 1 November 1993. Unless terminated on 12-months' notice, the contract is extended annually subject to regulatory approvals. The contract provides for an MDQ of 1 443 10^3m^3 (51,738 MMBtu or 51.0 MMcf) to be delivered at the Alberta/British Columbia border. Shell and Edison stated that the contract was negotiated at arm's length.

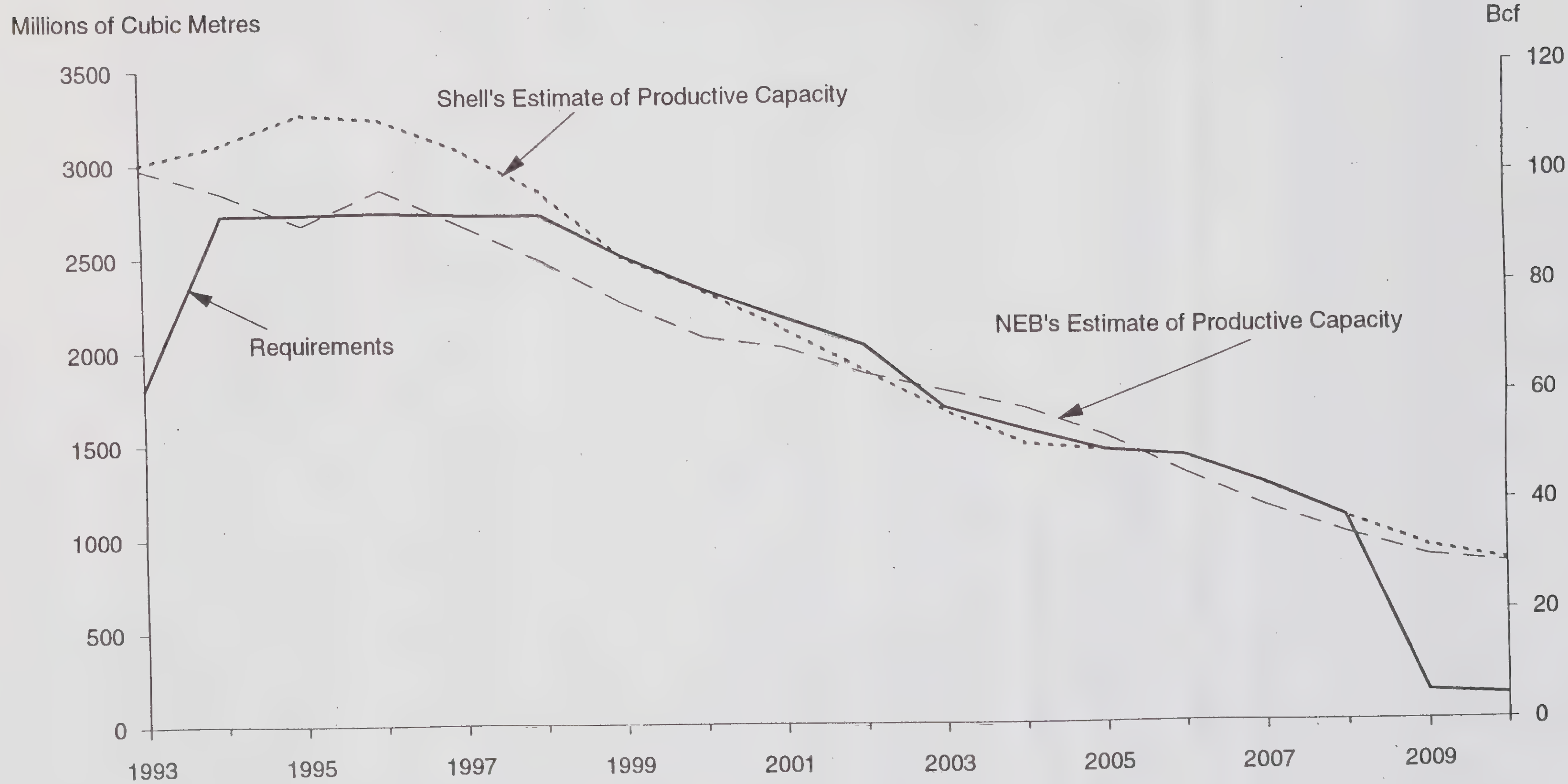
The BQ under the contract is 70 percent of the MDQ. The BQ is priced for a contract year based on the EACOG for the preceding year, adjusted through annual negotiation of the EACOG Multiplier. If the negotiations of the EACOG Multiplier are unsuccessful, the BQ price for that contract year will be the EACOG of the prior year multiplied by the AF. The BQ price excludes transportation rates, calculated at a 100 percent load factor, on PGT, PG&E and ANG/Foothills.

Should the average BQ price, over a three-year period, be ten percent more or less than the WACOG paid by other privately-owned California gas and/or electric utilities, the price paid for BQ gas for a contract year will be the previous year's WACOG price, plus or minus ten percent, and adjusted through annual negotiation. If negotiations are unsuccessful, an AF will be determined and applied. The WACOG will be used to determine the BQ price until the three-year average EACOG price falls within ten percent of the WACOG. The BQ price will then be determined using the EACOG.

The price for the AQ of up to 30 percent of the MDQ equals 90 percent of the BQ price.

Figure 11-1

Comparison of Shell's & NEB's Estimates of Annual Productive Capacity



Edison is obligated to nominate an MMQ that is 70 percent of the sum of MDQ's for each day of the month. Edison must pay a deficiency charge equal to 20 percent of the BQ price less transportation charges downstream of the Alberta/British Columbia border on the difference between actual nominations and the MMQ.

The estimated netback price that would have been in effect under the terms of this contract at the delivery point on 1 January 1992 was $1.74/GJ ($1.84/MMBtu) assuming incremental tolls on PGT and PG&E. Edison stated it would be responsible for incremental tolls applied to the required new compression facilities on SoCalGas.

11.5 Status of Regulatory Authorizations and Contract Approvals

Shell applied to the ERCB to amend gas removal permit GR89-47 on 18 June 1991. A decision on the application is pending. DOE/FE and facility expansion authorizations are discussed in Section 9.5 of these Reasons.

11.6 Views of the Board

The Board notes that Edison is obligated to make minimum monthly gas nominations if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing Edison market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board observes that the contract price is market sensitive as it is negotiated annually. As well, the Board takes comfort in Edison and Shell's evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contracts will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned by Shell, a finding of producer support is not necessary.

The Board notes that Edison is responsible for transportation charges on ANG/Foothills. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves exceeds Shell's total requirements and the Board's projection of productive capacity suggests that Shell can meet its requirements throughout the majority of the term of the proposed export licence. The Board is satisfied that Shell could alleviate any shortfalls through purchases of gas or by using gas from other Shell pools. The Board also observes that the term of the gas sales contract is 15 years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume commensurate with the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

11.7 Decision

The Board has decided to issue a gas export licence to Edison and Shell, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Southern California Edison Company and Western Gas Marketing Limited

12.1 Application Summary

By application dated 17 January 1991, Edison and Western Gas applied jointly for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	commencing on the later of 1 November 1993 or the date when firm transportation is available for the full volume on the pipeline systems of NOVA, ANG/Foothills, PGT, PG&E and SoCalGas, for a term of 15 years
Point of Export	-	near Kingsgate, British Columbia
Maximum Daily Quantity	-	1 445 10^3m^3 (51.0 MMcf)
Maximum Annual Quantity	-	529 10^6m^3 (18.7 Bcf)
Maximum Term Quantity	-	7 913 10^6m^3 (279.4 Bcf)
Tolerances	-	ten percent per day and two percent per year

The gas proposed for export would be produced in Alberta from reserves under contract to Western Gas. The gas would be transported in Canada on NOVA and ANG/Foothills to the international border near Kingsgate, British Columbia. In the U.S., the gas would flow through the PGT, PG&E and SoCalGas systems for delivery to Edison. Edison is an electric utility operating in central and southern California.

12.2 Gas Supply

In support of its application, Western Gas relied primarily upon the gas supply analysis that it provided to the Board during the GH-5-92 proceeding. The Board based its review of Western Gas' supply on the Board's extensive analysis of the supply information provided in GH-5-89 updated with evidence provided in this proceeding. Recognizing that Western Gas' supply situation has remained substantially unchanged, the Board did not consider it necessary to conduct a detailed review of Western Gas' reserves and productive capacity at this time. However, the Board's ongoing review of gas supply, which includes many of Western Gas' pools, has been incorporated into its current estimate of Western Gas' remaining reserves. Details of the Board's earlier analysis are provided in the GH-5-89 Reasons for Decision and as an Appendix to the GH-3-91 Reasons for Decision.

Table 12-1

Comparison of Estimates of Western Gas' Established Gas Reserves with the Applied-for Term Volume

10^9m^3
(Tcf)

Western Gas[1]	NEB[1]	Applied-for[2] Volume
501 (17.7)	434 (15.3)	7.9 (0.28)

1. as of 31 December 1991
2. These volumes represent only a portion of Western Gas' total commitments that must be provided from its supply pool. Western Gas' total contracted commitments over the next 15 years, including the applied-for volumes, are 280 10^9m^3 (9.9 Tcf).

12.2.1 Supply Contracts

Western Gas intends to supply the proposed export from its supply pool. Accordingly, no specific pools have been contractually dedicated to the sale. Should Western Gas' remaining reserves to production ratio ("RR/P") fall below ten, then it cannot enter into or renew any sales contracts. If it still cannot meet its obligations, Western Gas is then required to deliver to Edison a pro-rata share of the gas supply available. Western Gas' current estimate of the RR/P is greater than ten over the five-year projection period.

Western Gas updated the evidence provided in GH-5-89 regarding the outlook for terminations of producers' supply contracts. This update reflected notices of contract terminations received during 1990, 1991 and 1992. The notices received will affect Western Gas' supply in the 1994/95, 1995/96 and 1996/97 contract years.

12.2.2 Reserves

Table 12-1 shows that the Board's estimate of Western Gas' gas reserves is 15 percent lower than the applicant's estimate. While the Board's estimate of Western Gas' reserves is about 55 percent greater than Western Gas' total contracted requirements to the year 2008, it is only 81 percent of Western Gas' expected requirements over that period. The total contracted requirements assume no evergreening of existing contracts whereas expected requirements do assume evergreening of existing contracts.

12.2.3 Productive Capacity

Western Gas submitted projections of productive capacity that reflected its most recent estimates of established reserves and the notices of producer contract terminations received to 31 October 1992.

The Board has updated its productive capacity projection from GH-5-89 to 1992 to account for actual production. Figures 12-1 and 12-2 show comparisons of the Board's and Western Gas' projections of adjusted productive capacity with Western Gas' "Expected" and "Contracted" requirements respectively.

Both requirements projections take into account the amount of excess volume gas forecast by Western Gas to be produced from Western Gas' supply. The Board's projection reflects the effects of actual contract terminations received to 31 October 1992. The Board has not considered any terminations past those received to date, nor any effect to Western Gas' supply of producers exercising the volume reduction entitlement option available to producers under Western Gas' Netback Agreement.

Figure 12-1 shows that Western Gas can only meet its total expected requirements from currently established reserves to the year 1995. Figure 12-2 shows that Western Gas can meet its total contracted requirements from currently established reserves throughout the forecast period. In both cases the Board has adjusted its productive capacity projections to reflect production at the total indicated level of requirements.

12.3 Transportation

Western Gas holds sufficient firm transportation delivery service on NOVA to the Alberta/British Columbia border near Coleman, Alberta. Edison's transportation arrangements downstream of the NOVA outlet are discussed in Section 9.3 of these Reasons.

12.4 Markets and Sales Contracts

A discussion of the Edison market is presented in Section 9.4 of these Reasons.

Western Gas and Edison executed a gas sales contract dated 18 December 1990. The contract term begins with the commencement of firm deliveries and continues for 15 years. Firm deliveries are expected to commence on 1 November 1993. Unless terminated on 12-months' notice, the contract is extended annually subject to regulatory approvals. The contract provides for an MDQ of 1 466 10^3m^3 (52,565 MMBtu or 51.8 MMcf) to be delivered at the Alberta/British Columbia border. Western Gas and Edison stated that the contract was negotiated at arm's length.

The BQ under the contract is 70 percent of the MDQ. The BQ is priced for a contract year based on the EACOG for the preceding year, adjusted through annual negotiation of the EACOG Multiplier. If the negotiations of the EACOG Multiplier are unsuccessful, the BQ price for that contract year will be the EACOG of the prior year multiplied by the AF.

Should the average BQ price, over a three-year period, be 15 percent more or less than the WACOG paid by other privately-owned California gas and/or electric utilities, the price paid for BQ gas for a contract year will be the previous year's WACOG price, plus or minus 15 percent, and adjusted through annual negotiation. If negotiations are unsuccessful, an AF will be determined and applied. The WACOG will be used to determine the BQ price until the

Figure 12-1

Comparison of Western Gas' and NEB's Estimates of Productive Capacity with Expected Requirements

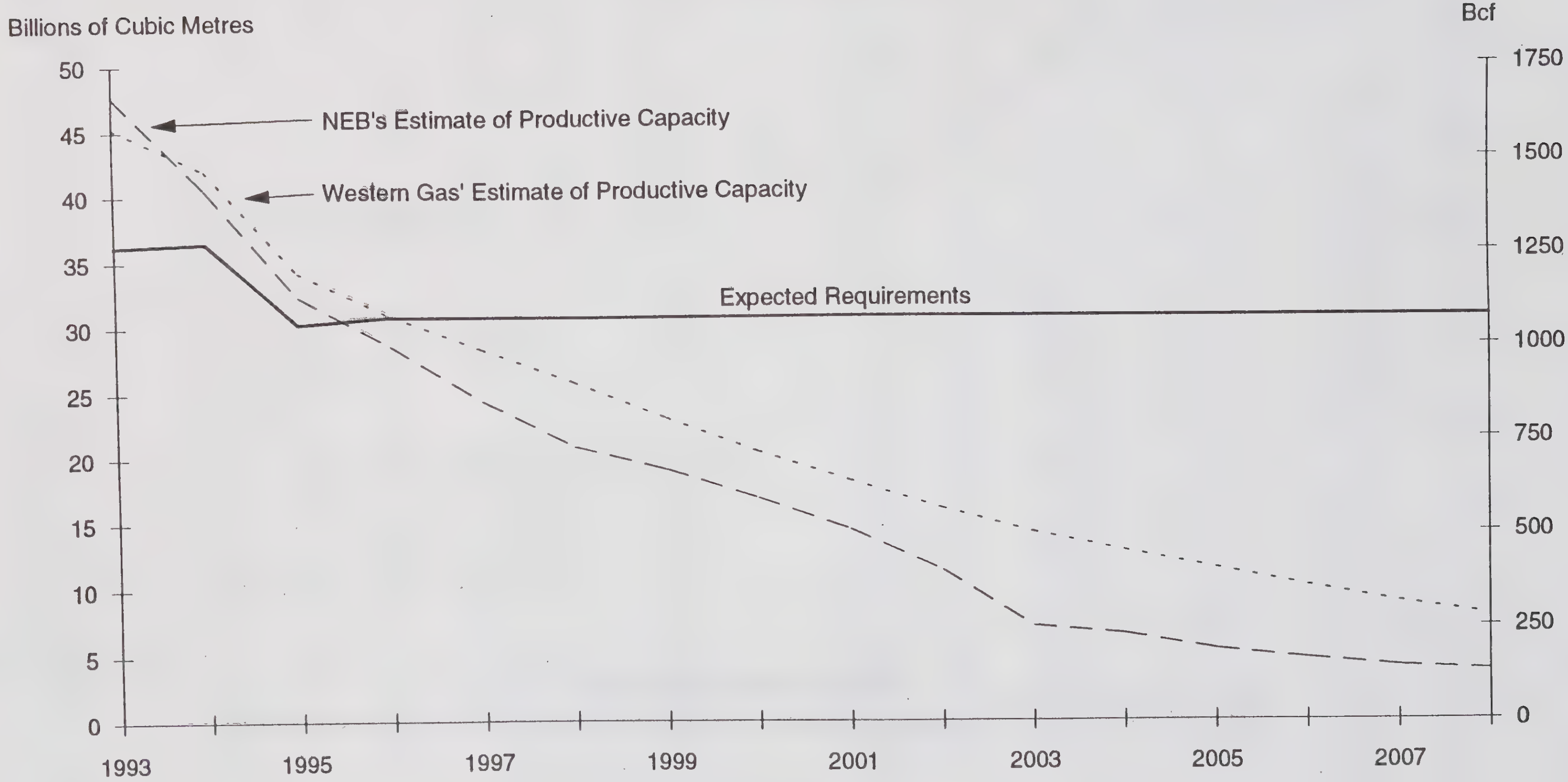
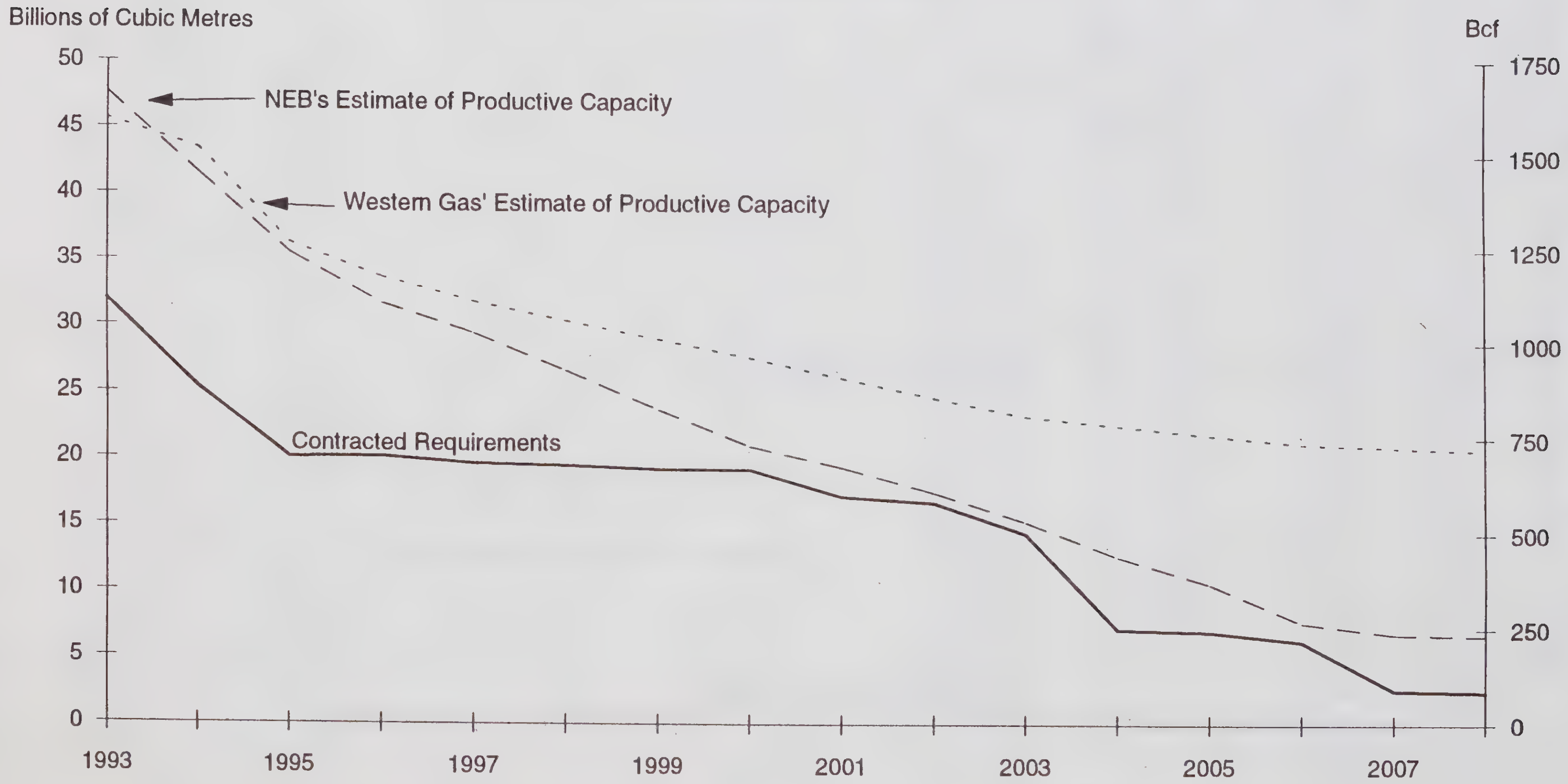


Figure 12-2

Comparison of Western Gas' and NEB's Estimates of Productive Capacity with Contracted Requirements



three-year average EACOG price falls within 15 percent of the WACOG. The BQ price will then be determined using the EACOG.

The quantity, price and other commercial terms for the AQ of up to 30 percent of the MDQ will be negotiated annually. If negotiations are unsuccessful, Western Gas is not obligated to sell and Edison is not obligated to buy the AQ. Western Gas and Edison will each bear their respective unused transportation costs.

Edison is obligated to nominate an MAQ that is 70 percent of the sum of MDQ's for each day of the year. Edison must pay a deficiency charge equal to 20 percent of the BQ price less transportation charges downstream of the Alberta/British Columbia border on the difference between actual nominations and the MAQ.

The estimated netback price that would have been in effect under the terms of this contract at the delivery point on 1 January 1992 was $1.64/GJ ($1.73/MMBtu) assuming incremental tolls on PGT and PG&E. Edison stated it would be responsible for incremental tolls applied to the required new compression facilities on SoCalGas.

12.5 Status of Regulatory Authorizations and Contract Approvals

Western Gas applied to the ERCB on 19 September 1991 to amend gas removal permit GR91-1. A decision on the application is pending. Western Gas obtained a finding of producer support from the APMC on 30 April 1991. DOE/FE and facility expansion authorizations are discussed in Section 9.5 of these Reasons.

12.6 Views of the Board

The Board notes that Edison is obligated to make minimum monthly gas nominations if it is to avoid payment of a deficiency charge. The Board also recognizes that the growing Edison market is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board observes that the contract price is market sensitive as it is negotiated annually. As well, the Board takes comfort in Edison and Western Gas' evidence that it is unlikely that any circumstances would occur that would cause either party to terminate the gas sales contract. The Board is thus satisfied that the sales contracts will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas sales contract and notes that it has been negotiated at arm's length.

Western Gas obtained a finding of producer support from the APMC on 30 April 1991.

The Board notes that Edison is responsible for transportation charges on ANG/Foothills. As well, the Board is of the view that the netback price will be sufficient to recover the demand charges on NOVA. The Board is therefore satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of Western Gas' reserves exceeds the applicant's total contracted requirements, including the volumes applied-for. The Board's projections of productive capacity show that Western Gas should be able to meet its contracted requirements throughout the term of

the applied-for licence. However, Western Gas can only meet its expected requirements until 1995. The Board agrees with Western Gas that, in making its decision, the Board should examine gas supply to meet contracted requirements rather than expected requirements. The Board also observes that the term of the gas sales contract is 15 years. The Board notes that transportation has been arranged on all required pipelines and that the contract terms range from 15 to 30 years. The regulatory authorizations either applied-for or received are for a term and volume commensurate with the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

12.7 Decision

The Board has decided to issue a gas export licence to Edison and Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Chapter 13

Summit Resources Limited

13.1 Application Summary

By application dated 17 October 1991, Summit applied for a natural gas export licence, pursuant to Part VI of the Act, with the following terms and conditions:

Term	-	seven years commencing on the later of 1 November 1993, the date when the parties have obtained all regulatory approvals, or the date when firm transportation is available on NOVA, ANG/Foothills, PGT and Northwest.
Point of Export	-	Kingsgate, British Columbia
Maximum Daily Quantity	-	219.2 10^3m^3 (7.7 MMcf) in winter
	-	141.3 10^3m^3 (5.0 MMcf) in summer
Maximum Annual Quantity	-	52.8 10^6m^3 (1.9 Bcf)
Maximum Term Quantity	-	300 10^6m^3 (10.7 Bcf)
Tolerances	-	ten percent per day and two percent per year.

The gas proposed for export would be produced from Summit's reserves in Alberta. The gas would be transported in Canada on NOVA and ANG/Foothills to the international border near Kingsgate, British Columbia. In the U.S., PGT and Northwest would ship the gas to Northwest Natural, an LDC serving markets in the states of Washington and Oregon.

13.2 Gas Supply

13.2.1 Reserves

Summit will provide the gas for the proposed export from its uncontracted corporate reserves. A list of uncontracted pools from these corporate reserves was submitted in support of Summit's application. Table 13-1 shows that the Board's estimate of Summit's established gas reserves is seven percent higher than Summit's and exceeds the applied-for volume by 31 percent.

Summit also provided estimates of "development reserves" of 238 10^6m^3 (8 Bcf) on 12 sections of land in the Sorenson Lake and Bloor areas of Alberta. Summit defined development reserves as reserves that are gas prone based on geophysical, geological and engineering data. In estimating these reserves, Summit assigned a discount factor of 40 percent. Summit had not developed these reserves to date as there was no requirement for the gas. These reserves could, however, be developed in support of the export to Northwest Natural. The Board's estimate of these development reserves is approximately 209 10^6m^3 (7 Bcf), which is 12 percent lower than Summit's estimate.

Table 13-1

Comparison of Estimates of Summit's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Summit[1]	NEB[2]	Applied-for Volume
367 (13)	394 (14)	300 (11)

1. As of 1 January 1992. In addition to the established gas reserves estimate, Summit also submitted an estimate of 238 10^6m^3 (8 Bcf) as its working interest share of development reserves.
2. As of 31 December 1991.

13.2.2 Productive Capacity

Figure 13-1 compares the Board's and Summit's projections of productive capacity with the applied-for annual volumes. The Board based its estimate of adjusted productive capacity upon the applied-for annual volumes, although Summit indicated that annual requirements are likely to be reduced by 18 percent due to seasonal load factors. If the Board's analysis used these expected requirements, then its results would be closer to Summit's. Both analyses show that Summit could meet its annual requirements from the submitted reserves for approximately four and one-half years of the seven-year term. The remaining requirements are expected to be met by the development reserves discussed above and by reserves additions resulting from its exploration efforts or by the acquisition of third-party gas.

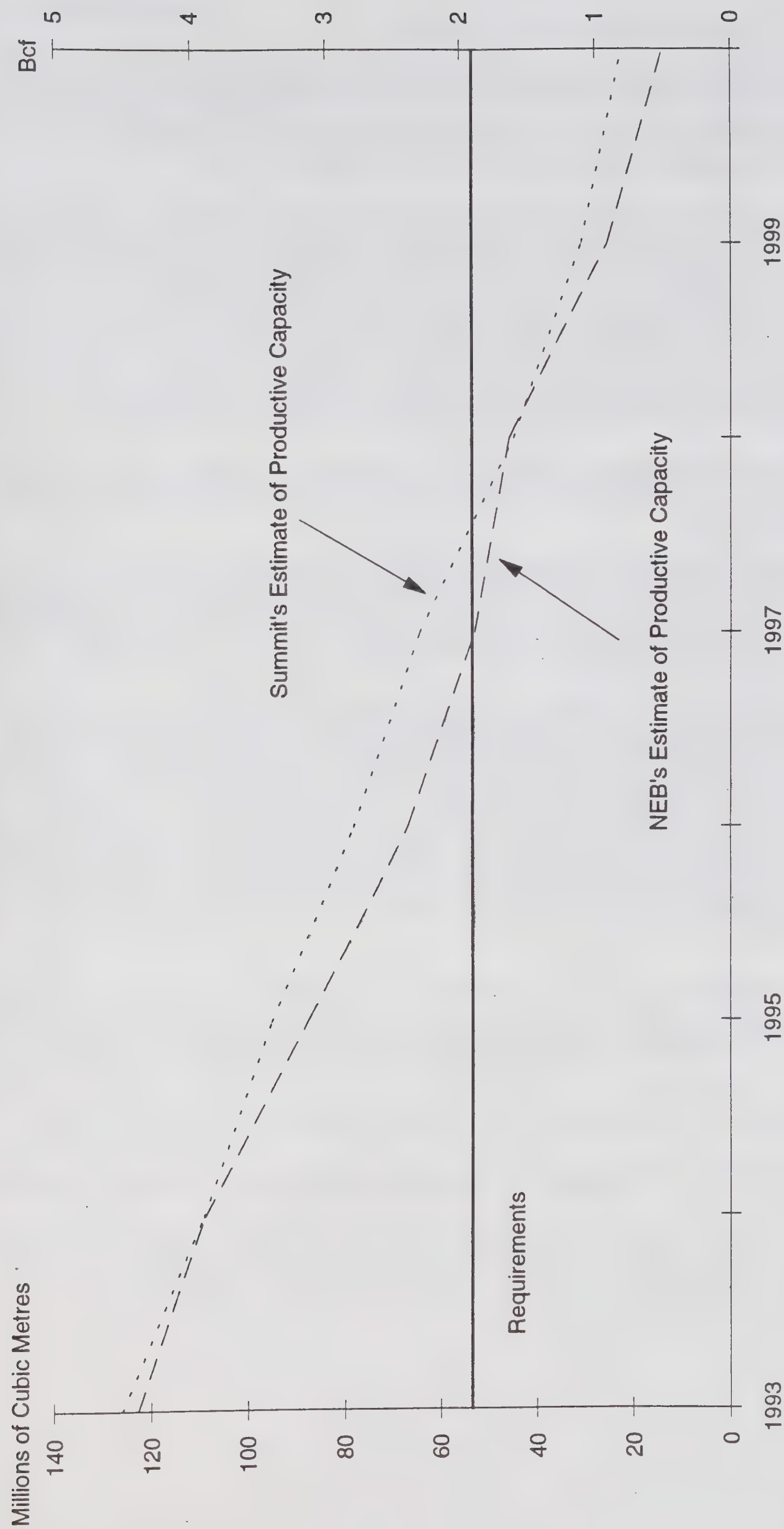
13.3 Transportation

Summit executed an FS contract, dated 1 September 1991, with NOVA to deliver the proposed export volumes from receipt points in Alberta to the British Columbia border at Coleman. Northwest Natural concluded a contract with ANG, dated 12 June 1991, to transport the gas on ANG/Foothills' system to the international boundary near Kingsgate, British Columbia. Northwest Natural will temporarily assign a portion of its ANG/Foothills capacity to Summit for a term and volume consistent with the gas sales contract.

A discussion of the transportation arrangements downstream of Kingsgate is presented in Section 4.3 of these Reasons. All transportation agreements are for a term and volume commensurate with the subject application.

Figure 13-1

Comparison of Summit's and NEB's Estimates of Annual Productive Capacity



13.4 Market and Sales Contracts

A discussion of the Northwest Natural market is presented in Section 4.4 of these Reasons.

Summit expected that exports would occur at summer and winter load factors of 50 and 75 percent respectively, for an annual average of nearly 65 percent.

Northwest Natural and Summit executed a gas purchase contract on 1 June 1991, with an initial term of seven years, commencing on the later of 1 November 1993 or the fulfillment of all conditions precedent. The contract continues year-to-year thereafter until cancelled by either party on six-month's written notice. The contract provides for a WMDQ and SMDQ of 219.2 10^3m^3 (7.7 MMcf) and 141.3 10^3m^3 (5.0 MMcf) respectively and is subject to the satisfaction of all conditions precedent, including receipt of regulatory authorizations, the existence of executed transportation agreements and the completion of pipeline expansions by 31 July 1994. Summit stated that the contract was negotiated at arm's length.

Northwest Natural must purchase at least 75 percent of the WMDQ during the winter season. If it does not, Northwest Natural will pay a fee of 20 percent of the first tier commodity price on the deficient quantity.

The contract includes a two-part pricing structure, consisting of a demand charge and a commodity price, at the point of delivery. The contractual point of delivery is the interconnection of the NOVA and ANG/Foothills systems. The parties, however, amended the contract on 30 October 1992 to provide an option to Summit to change the point of delivery to Kingsgate.

The demand charge component will be a monthly amount equal to Summit's demand charge obligations to transport the export volumes to the delivery point. The commodity component will be divided into three tiers. The first tier will reflect a price applicable to purchases in the winter season. The second and third tiers are intended to provide incentive pricing for the shoulder and summer seasons, and will generally be lower than the first tier price. The parties will negotiate mutually acceptable commodity prices annually. The contract states that the commodity prices shall ensure that the gas is competitively priced compared to Northwest Natural's other long-term Canadian and U.S. supply sources and Summit's alternate markets for Alberta gas, under similar load factors.

The contract provides for binding arbitration in the event that Summit and Northwest Natural are unable to agree on the commodity prices. Arbitration would consider, among other things, the price of other gas sold under similar service and conditions in the same or similar markets.

Summit submitted that, on 1 January 1992, the Alberta border price that would have been in effect under the terms of this contract would have been $1.51/GJ ($1.59/MMBtu).

13.5 Status of Regulatory Authorizations and Contract Approvals

On 18 October 1991, Summit applied to the ERCB for a removal permit. A decision on the application is pending. As well, Northwest Natural applied to the DOE/FE for import authorization on 10 December 1991. A decision is expected early in 1993.

13.6 Views of the Board

The Board notes that Northwest Natural must purchase at least 70 percent of the WMDQ if it is to avoid payment of a deficiency charge. The Board also recognizes that the market for the gas is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes to be licensed will be taken.

The Board has noted the market-oriented approach, including binding arbitration, used to determine the commodity prices on an annual basis. As well, the Board takes comfort in Summit's evidence that it is unlikely that any circumstances would occur that would cause Summit and Northwest Natural to terminate the gas sales contract. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas purchase contract and notes that it has been negotiated at arm's length.

As the gas proposed for export would come from reserves owned or controlled by Summit, a finding of producer support is not necessary.

The Board notes that the contract price contains a demand charge component equal to Summit's demand charge obligations to transport the export volumes to the delivery point. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves substantially exceeds Summit's requirements. The Board's estimate of productive capacity exceeds Summit's requirements for most of the applied-for term. The Board is satisfied that Summit can meet its requirements throughout the applied-for term by the development of new reserves and by using other reserves in its corporate portfolio. The Board notes that applications for a removal permit and DOE/FE import authorization have been made and that all other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contract are consistent with the proposed term of the licence. The Board is therefore satisfied that the requested licence term is appropriate.

13.7 Decision

The Board has decided to issue a gas export licence to Summit, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence.

Chapter 14

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of those applications heard by the Board in the GH-6-92 proceedings.

K.W. Vollman
Presiding Member

A.B. Gilmour
Member

R. Illing
Member

Calgary, Alberta
January 1993

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to ENCO Gas, Ltd.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 May 1993 or the date of first deliveries and shall end on 31 October 2008.

   (b) The term of this Licence shall end on 1 May 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that ENCO may export under the authority of this Licence shall not exceed:

   (a) for the period commencing on the later of 1 May 1993 or the date of first deliveries and ending on 31 October 1993, 155 800 cubic metres in any one day, or 28 700 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (b) for the period commencing on 1 November 1993 and ending on 31 October 1994, 429 100 cubic metres in any one day, or 156 600 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (c) for the period commencing on 1 November 1994 and ending on 31 October 2008, 601 300 cubic metres in any one day, or 219 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (d) 3 258 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Huntingdon, British Columbia.

Terms and Conditions of the Licence to be Issued to The Washington Water Power Company

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 November 1993 or the date of first deliveries and shall end ten years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that WWP may export under the authority of this Licence shall not exceed:

   (a) for the period commencing on the later of 1 November 1993 or the date of first deliveries and ending on 31 October 1994, 1 013 000 cubic metres in any one day, or 277 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (b) for the period commencing on 1 November 1994 and ending on 31 October 1995, 1 100 000 cubic metres in any one day, or 302 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (c) for the period commencing on 1 November 1995 and ending on 31 October 1996, 1 190 000 cubic metres in any one day, or 328 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (d) for the period commencing on 1 November 1996 and ending on 31 October 1997, 1 285 000 cubic metres in any one day, or 356 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (e) for the period commencing on 1 November 1997 and ending on 31 October 1998, 1 380 000 cubic metres in any one day, or 382 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (f) for the period commencing on 1 November 1998 and ending on 31 October 1999, 1 471 000 cubic metres in any one day, or 408 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (g) for the period commencing on 1 November 1999 and ending on 31 October 2000, 1 563 000 cubic metres in any one day, or 434 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (h) for the period commencing on 1 November 2000 and ending on 31 October 2001, 1 145 000 cubic metres in any one day, or

275 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

(i) for the period commencing on 1 November 2001 and ending on 31 October 2002, 1 201 000 cubic metres in any one day, or 290 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

(j) for the period commencing on 1 November 2002 and ending on 31 October 2003, 1 258 000 cubic metres in any one day, or 305 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(k) 3 357 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to Poco Petroleums Ltd.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 November 1993 or the date upon which all conditions precedent contained in the Gas Purchase Contract dated 1 June 1991 between Poco Petroleums Ltd. and Northwest Natural Gas Company have been satisfied or waived and shall end on 30 September 2003.

(b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that Poco may export under the authority of this Licence shall not exceed:

(a) 445 100 cubic metres in any one day;

(b) 138 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 869 500 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to San Diego Gas & Electric Company and Bow Valley Industries Ltd.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of first deliveries and shall end 11 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 31 December 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the San Diego Gas & Electric and Bow Valley Industries Ltd. may export under the authority of this Licence shall not exceed:

   (a) 139 500 cubic metres in any one day;

   (b) 50 900 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 560 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to San Diego Gas & Electric Company and Canadian Hunter Marketing Ltd.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of first deliveries and shall end ten years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 31 December 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the San Diego Gas & Electric and Canadian Hunter Marketing Ltd. may export under the authority of this Licence shall not exceed:

(a) 557 600 cubic metres in any one day;

(b) 203 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 035 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to San Diego Gas & Electric Company and Husky Oil Operations Ltd.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of first deliveries and shall end ten years following the commencement of the term of this Licence.

(b) The term of this Licence shall end on 31 December 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the San Diego Gas & Electric and Husky Oil Operations Ltd. may export under the authority of this Licence shall not exceed:

(a) 609 900 cubic metres in any one day;

(b) 222 600 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 226 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to San Diego Gas & Electric Company and Summit Resources Limited

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the date of first deliveries and shall end eight years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 31 December 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the San Diego Gas & Electric and Summit Resources Limited may export under the authority of this Licence shall not exceed:

   (a) 195 100 cubic metres in any one day;

   (b) 71 200 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 570 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to Southern California Edison Company and AEC Oil and Gas Company a division of Alberta Energy Company Ltd.

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 November 1993 or the date when firm transportation is available on the pipeline systems of NOVA Corporation of Alberta, Alberta Natural Gas Company Ltd./Foothills Pipe Lines (South B.C.) Ltd., Pacific Gas Transmission Company, Pacific Gas & Electric Company and Southern California Gas Company and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the Southern California Edison Company and AEC Oil and Gas Company a division of Alberta Energy Company Ltd. may export under the authority of this Licence shall not exceed:

   (a) 1 445 000 cubic metres in any one day;

   (b) 529 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 7 913 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to Southern California Edison Company and Imperial Oil Resources Limited

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 November 1993 or the date when firm transportation is available on the pipeline systems of NOVA Corporation of Alberta, Alberta Natural Gas Company Ltd./Foothills Pipe Lines (South B.C.) Ltd., Pacific Gas Transmission Company, Pacific Gas & Electric Company and Southern California Gas Company and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the Southern California Edison Company and Imperial Oil Resources Limited may export under the authority of this Licence shall not exceed:

   (a) 1 445 000 cubic metres in any one day;

   (b) 529 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 7 913 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to Southern California Edison Company and Shell Canada Limited

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of the date upon which all conditions precedent contained in the Gas Sales and Purchase Agreement dated 18 December 1990 between Southern California Edison Company and Shell Canada Limited have been satisfied or waived or the date when firm transportation is available on the pipeline systems of NOVA Corporation of Alberta, Alberta Natural Gas Company Ltd./Foothills Pipe Lines (South B.C.) Ltd., Pacific Gas Transmission Company, Pacific Gas & Electric Company and Southern California Gas Company and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the Southern California Edison Company and Shell Canada Limited may export under the authority of this Licence shall not exceed:

   (a) 1 445 000 cubic metres in any one day;

   (b) 529 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 7 913 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to Southern California Edison Company and Western Gas Marketing Limited

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 November 1993 or the date when firm transportation is available on the pipeline systems of NOVA Corporation of Alberta, Alberta Natural Gas Company Ltd./Foothills Pipe Lines (South B.C.) Ltd., Pacific Gas Transmission Company, Pacific Gas & Electric Company and Southern California Gas Company and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that the Southern California Edison Company and Western Gas Marketing Limited may export under the authority of this Licence shall not exceed:

   (a) 1 445 000 cubic metres in any one day;

   (b) 529 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 7 913 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.

Terms and Conditions of the Licence to be Issued to Summit Resources Limited

1. (a) Subject to condition 1(b), the term of this Licence shall commence on the later of 1 November 1993 or the date upon which all conditions precedent contained in the Gas Purchase Contract dated 1 June 1991 between Summit Resources Limited and Northwest Natural Gas Company have been satisfied or waived and shall end seven years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that Summit may export under the authority of this Licence shall not exceed:

(a) for the period commencing on 1 October in each calendar year and ending on 31 March in the next succeeding calendar year, 219 200 cubic metres in any one day;

(b) for the period commencing on 1 April and ending on 30 September in any calendar year, 141 300 cubic metres in any one day;

(c) 52 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(d) 300 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Kingsgate, British Columbia.